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A METHOD FOR UTILITY LOAD MANAGEMENT
USING SHORT TERM LOAD FORECASTING

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Final Report 4 May 1978

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A thesis submitted to the University of Vermont, Burlington, VT. in partial fulfillment of the requirements for the degree of Master of Electrical Engineering.

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Several models for forecasting short term utility system loads are examined. A hybrid linear model is developed and used to simulate improvements to a utility load factor by providing the basis for scheduling deferred loads (TES). Results of simulations for 1976-1977 on a Vermont utility yielded average hourly forecast errors of 5%.

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A METHOD FOR UTILITY LOAD MANAGEMENT
USING SHORT TERM LOAD FORECASTING

A Thesis Presented

by

Robert Brian Ottesen

to

The Faculty of the Graduate College

of

The University of Vermont

In Partial Fulfillment of the Requirements

for the Degree of Master of Science

May, 1978

Accepted by the Faculty of the Graduate College, the University of Vermont, in partial fulfillment of the requirements for the degree of Master of Science, specializing in Electrical Engineering.

Thesis Committee: Gagan Mirchandani Advisor
Dr. Gagan Mirchandani

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Date April 28, 1978

ABSTRACT

A description of a linear model for forecasting short term utility loads is presented. The model is used to simulate the improvement to the utility load factor by providing a basis for scheduling deferred loads. Simulations were performed using data from Central Vermont Public Service Corporation for the period 1976-1977. The results indicate that an average hourly prediction error of less than 5% is possible with this model, and that an increase in the utility system load factor is directly related to the magnitude of the controllable load.

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CHAPTER I

INTRODUCTION

I. Introduction

An electric utilities' loads are graphically examined and a basic terminology is presented.

I. 1.0 Objectives

The primary purpose of this study is to investigate the impact which scheduling of deferred loads will have on the load factor of utilities. Collaterally the problem of short term load forecasting, in order to optionally schedule loads, became an equally important area for investigation. Once the future load pattern has been forecast, then for a given controllable load the off peak system load be increased with potential benefits to both the utility and the consumer. These features were simulated using a two year period of load data from a Vermont utility.

I. 2.0 Background

A basic understanding of the electric utility industry in the

United States and particularly in New England was required as a starting point for the load forecasting phase. Prior knowledge of system loads, a load forecast, would enable a utility to schedule its generating capacity to match its loads and hence reduce generating costs. In actuality individual utilities in Vermont have no such short term prediction available. Due primarily to the emergence of power-pools in the mid 1960's utilities no longer scheduled the operation of their own generating systems. This function was assumed in a regional basis by the power pools who in turn developed forecasting procedures for a much larger geographic area and higher system load. The number of technical papers published on load forecasting seems to have peaked in the early 1970's (Sachdev, 1977).

I. 3.0 Utility Responsibilities and Definitions

Most electric utilities are private corporations regulated by local governments in the public interest. Until recently each has been a monopoly within its area of responsibility. By law the utility is required to reliably supply all of the power its customers demand, where power is defined as the electric load, or total utility system load, at time t. It is generally integrated

over an hour and recorded in units of megawatt hours (MWH). The demand varies over each time interval examined from seconds through years. Short term load fluctuation defined as those occurring from one through twenty-four hours in the future are important to the system operator, the individual responsible for insuring the uninterrupted flow of power. Longer term forecasting does not immediately apply to the system operator and often involves socio-economic factors. Shorter term forecasting (i.e. those system load fluctuations occurring from seconds to several minutes) appear to be white noise and are almost always small enough to be balanced by automatically adjusting the operating frequency of generating units (Galiana, 1971). It has been estimated that a 12% imbalance between generation and load results in a frequency change of 1 Hz. Major blackouts, such as those experienced by New York City, are characterized by line frequency shifts of from one to two Hz (Ewart, 1978).

The term 'load management' is defined as any action taken by an electric utility to manage its loads. Load management is subdivided into supply management where utilities modify the system load as seen from the generator ports without affecting individual customer's consumption patterns and customer management where the power demand pattern itself is modified in

some manner. The latter load management strategy commonly takes the form of promotion of conservation measures, promotion of off peak electric periods, or a rate structure which penalizes peak period consumption. Only recently in the United States has direct load control by the utility been added to the available methods of customer load management (Galiana, 1977). Here the utility actually controls or schedules the pattern of consumption in some manner. The operation of selected appliances may be controlled by radio frequency signals, coded pulses superimposed on the 60 Hz. line voltage (i.e. ripple control), or load timers. For the first time the system operator can shape the daily load curve and selectively shed loads in case of system emergencies.

Shaping the load curve to improve the system load factor impacts directly on the cost of power to the consumer. The load factor is a measure of the efficiency of the electrical system.

It is defined by the industry as:

$$\frac{\sum_{n=1}^{24} Z_n(t)}{\left[\max\ Z_n(t)\right] \times 24}$$

Z = System Load MWH

n = Time Periods

t = Time

Normally a utility measures its efficiency by its yearly load factor i.e. n = 8760 hours/year. Central Vermont Public Service Utility's 1977 load factor was approximately 60%. Obviously the simplest way to improve load factor is to reduce the maximum system demand. Controlling a substantial load through ripple signals and then being able to defer or shift that load to an off peak period accomplishes this reduction in maximum $Z_n(t)$.

Deferrability of most electric loads from the consumer's viewpoint is undesirable. The customer wants his lights to be on and appliances to work when he closes the switch. Similarly industrial motor loading is non-deferrable. However substantial electric power is consumed in heating homes and water. For a Vermont electric home the average heating load was 19,000 KWH from a total annual load of 25,000 KWH (Vermont Load Study,

1974). Resistive heating loads are deferrable to a certain extent since this electric energy can be stored in a heated medium for later consumption. Thermal Energy Storage (TES) is the commonly used term for this process. In Germany, buildings have employed TES heating for over twenty years and in certain regions it now accounts for over 45% of the region's peak load. There are now more than six million electrically heated residences throughout the United States, so the potential for load factor improvement through TES and customer load management exists. It is not a completely new or untried technology (Siemens, 1978).

Energy costs in Vermont are more than that of any other state in the continental United States. The weighted average price of one million fossil fuel BTUs paid by utilities was 61.7 cents in 1973. Today that same figure is $2.30 and in 1973 dollars it is still $1.80. That is a 373% increase in four years and also means that Vermont utilities pay 780% as much for fossil energy as the nation's cheapest state - North Dakota (Buggraf, 1978). Making the energy system more efficient is one way of reducing this cost disparity.

I. 4.0 Load Patterns

The question of forecasting what the system load will be has been approached in the literature many ways; however, all forecasting has been in some measure based on the total historical load pattern as opposed to a decomposition of the load. Hence the following pattern analysis will be a starting point. Data from Central Vermont Public Service Corp. was chosen due to its availability, although data from any utility could have been used.

I. 4.1 Monthly Pattern

Fig. 1 illustrates the periodic behavior of Central Vermont Public Utility's load for the month of April 1976. Note the weekend valleys and the general inverse load trend with increasing average temperature throughout the period. This perspective of the load was chosen in order to prevent the morning peak from masking the noon valley and evening peak.

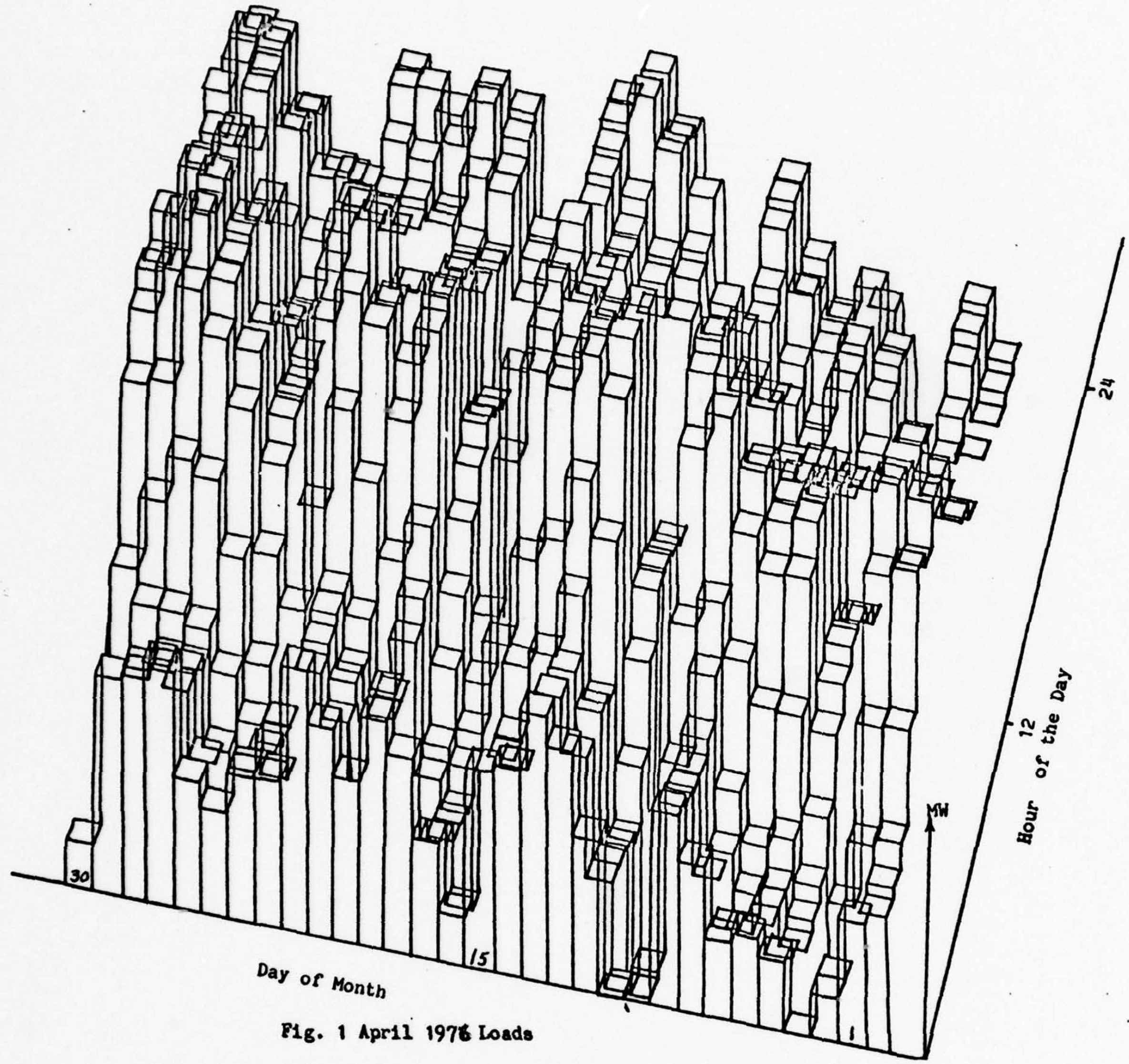


Fig. 1 April 1976 Loads

I. 4.2 Weekly Load Patterns

Fig. 2 illustrates the system load for a Sunday through Saturday period in May 1976. Again note the similarity of weekday versus weekend load levels. The pattern is especially pronounced on Tuesday through Friday and has lead some authors to consider the normal system load problem as being made up of three regions i.e. weekends, Tuesdays through Fridays and Mondays (Wernhof, 1978).

I. 4.3 Repeated Weekday Pattern

A deeper graphical appreciation of the similarities in system load for weekdays can be gained from Figures 3 and 4 which show load on consecutive Mondays and Thursdays in May 1977. Mondays lack the pronounced noonday load valley. Note the affect which the Memorial Day holiday had on the load. Holidays, of course, must be forecasted on a special case basis. A pronounced noon valley is characteristic of many utility systems and gives rise to the phrase "camel's hump load pattern". Note also that the load does not fluctuate greatly from one week to the next. Even in the seasonal transistion months the total daily load did not change by more than 20% over a weeks time.

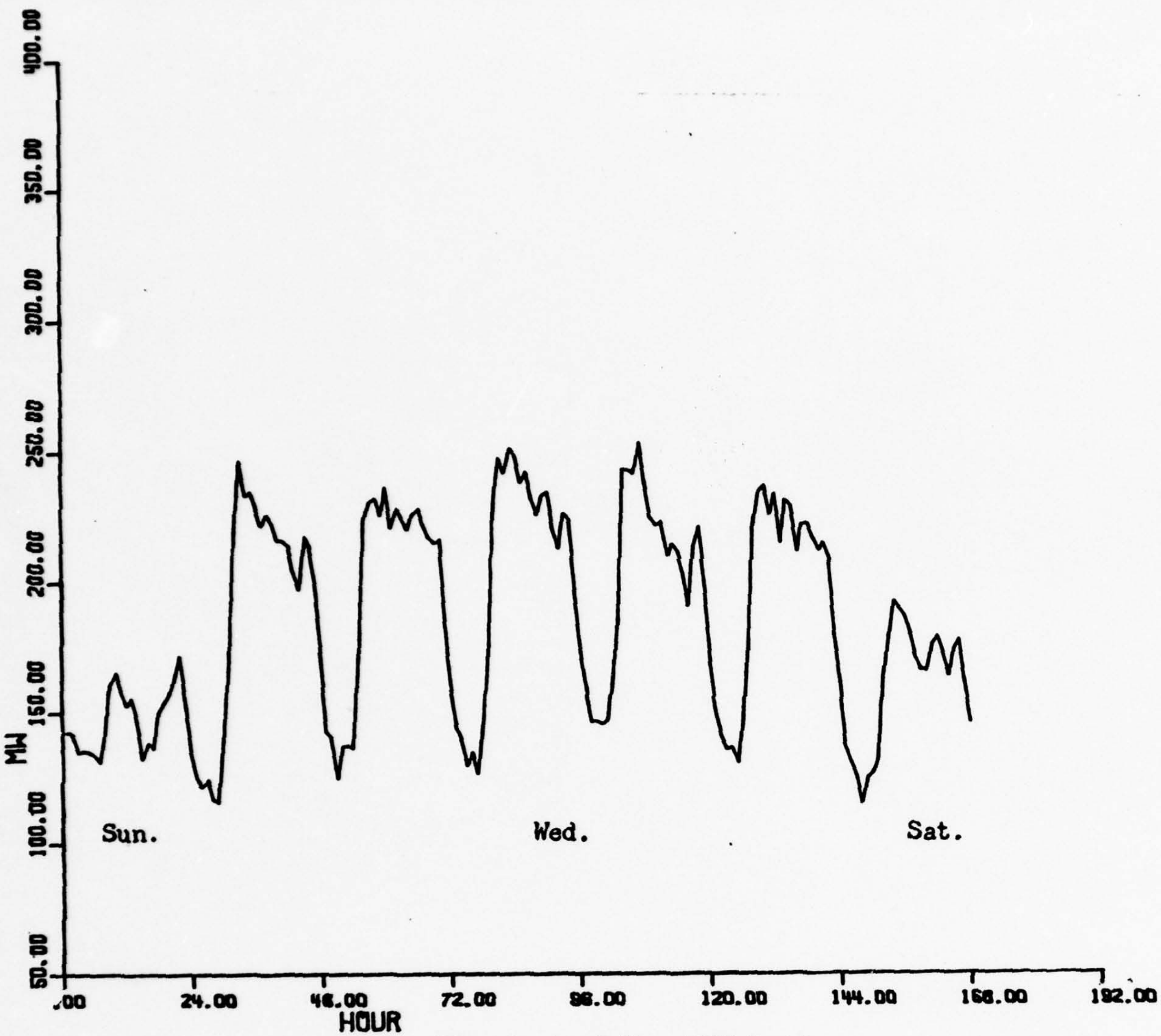


Fig. 2 9-15 May 1976 Loads

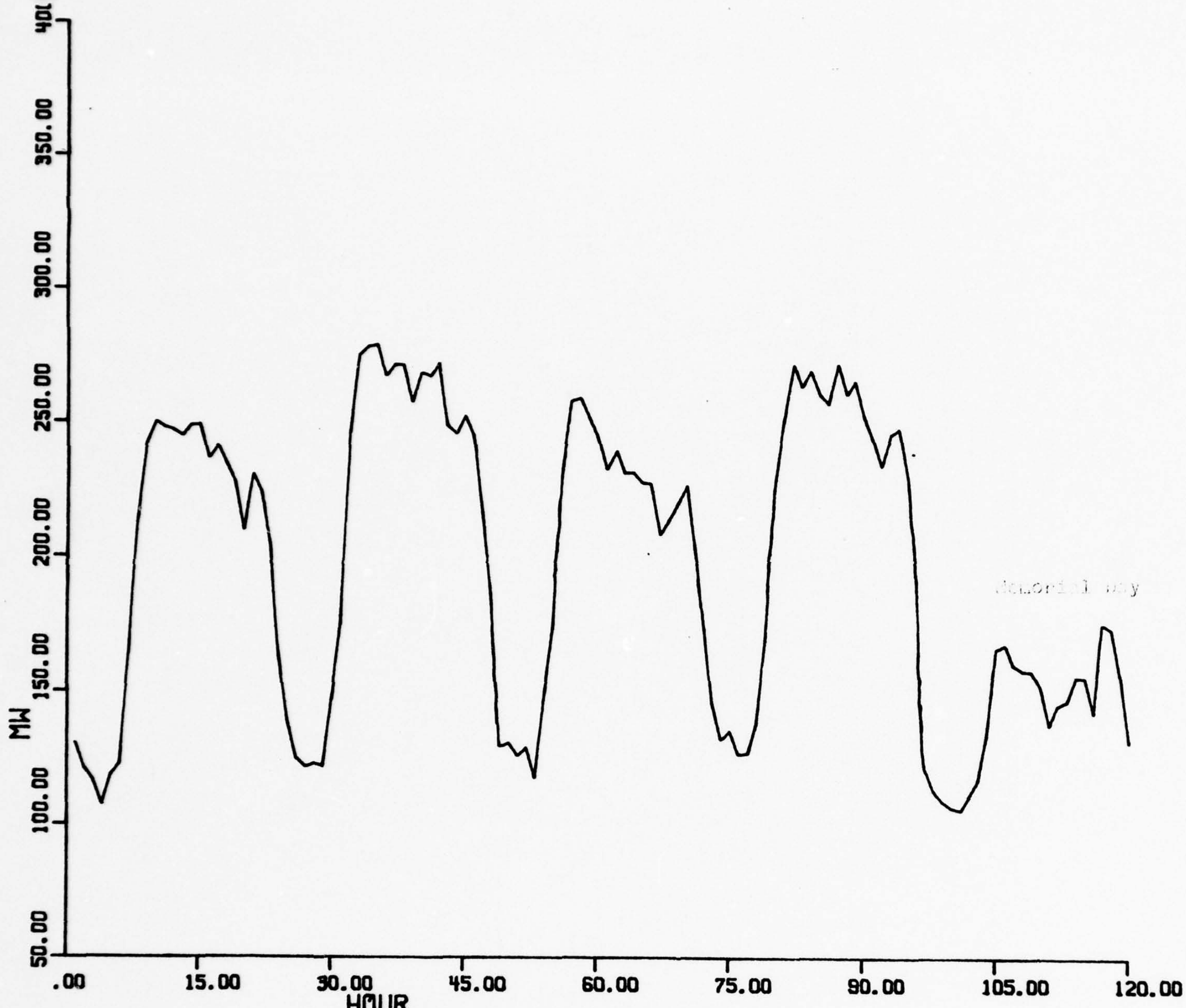


Fig. 3 May Mondays 1977

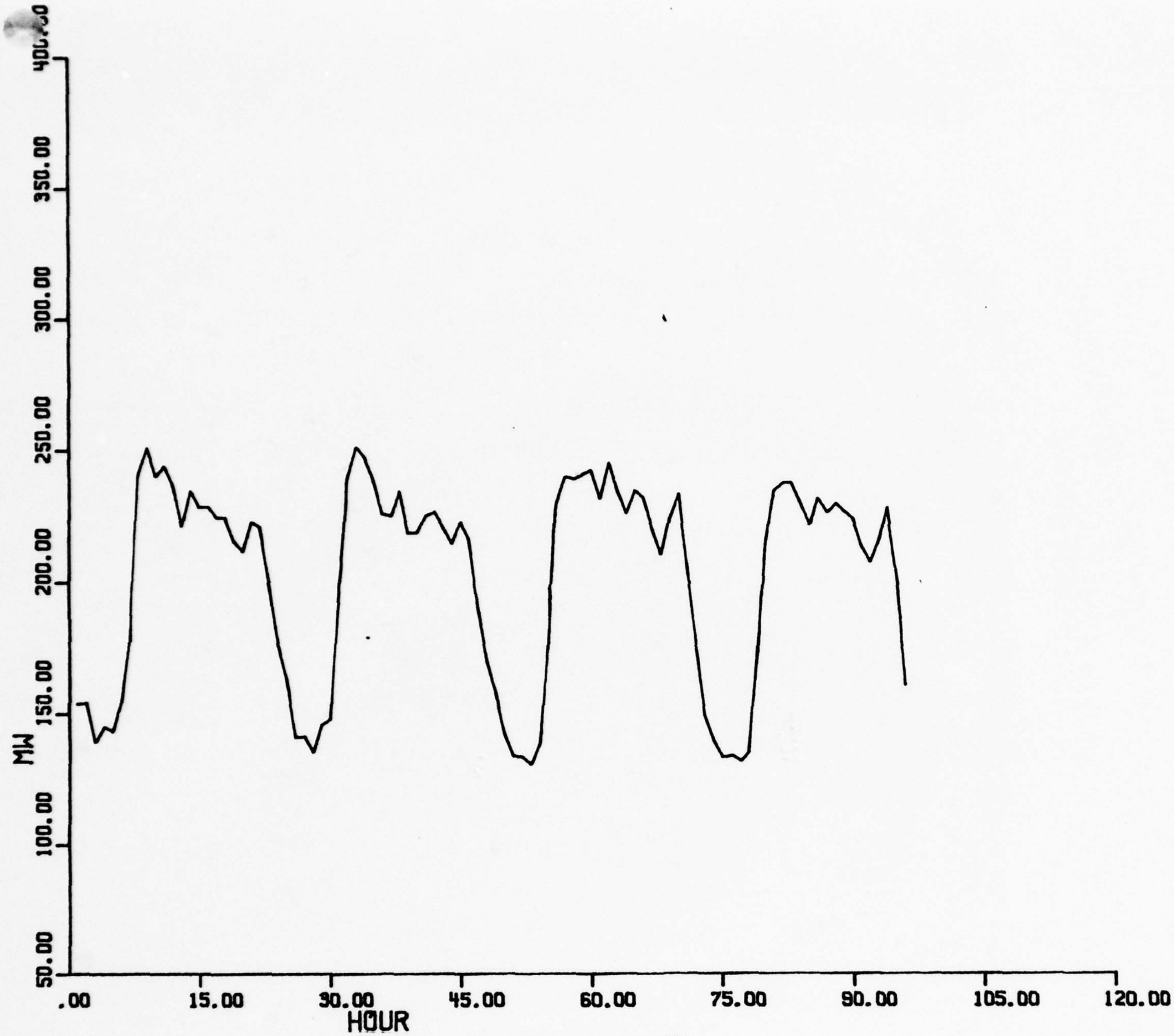


Fig. 4 May Thursdays 1977

I. 4.4 Similar Days Separated by N Periods

Fig. 5 shows the system loads for the second week of September 1976 and the same week one year later. The basic pattern is of course, the same; however, the electrical load has evolved enough to preclude merely using the "same day last year" as a basis for prediction this year. A legitimate question here would be, "Is a similar day last year a good prediction for this year?". Neglecting until Section III a discussion of what constitutes a good prediction leads to the problem of defining a similar day. Similar in what manner? Date, day of week, maximum and minimum temperature range, wind, cloud cover, precipitation, and weather trends are all possible factors in characterizing similarity. There is a high probability that similarity exists only in a subjective manner, especially since the system peak day is unique each year, and it has occurred randomly in the sixty day December-January time window. Fig. 6 illustrates the similarity of Thursdays separated by one week, one month, and one year. Their average daily temperature was within 5 degrees Fahrenheit throughout to minimize the temperature dependence of load. Temperature data for the utilities visited was maintained in Fahrenheit, and there was no discussion of plans to convert to Centegrade.

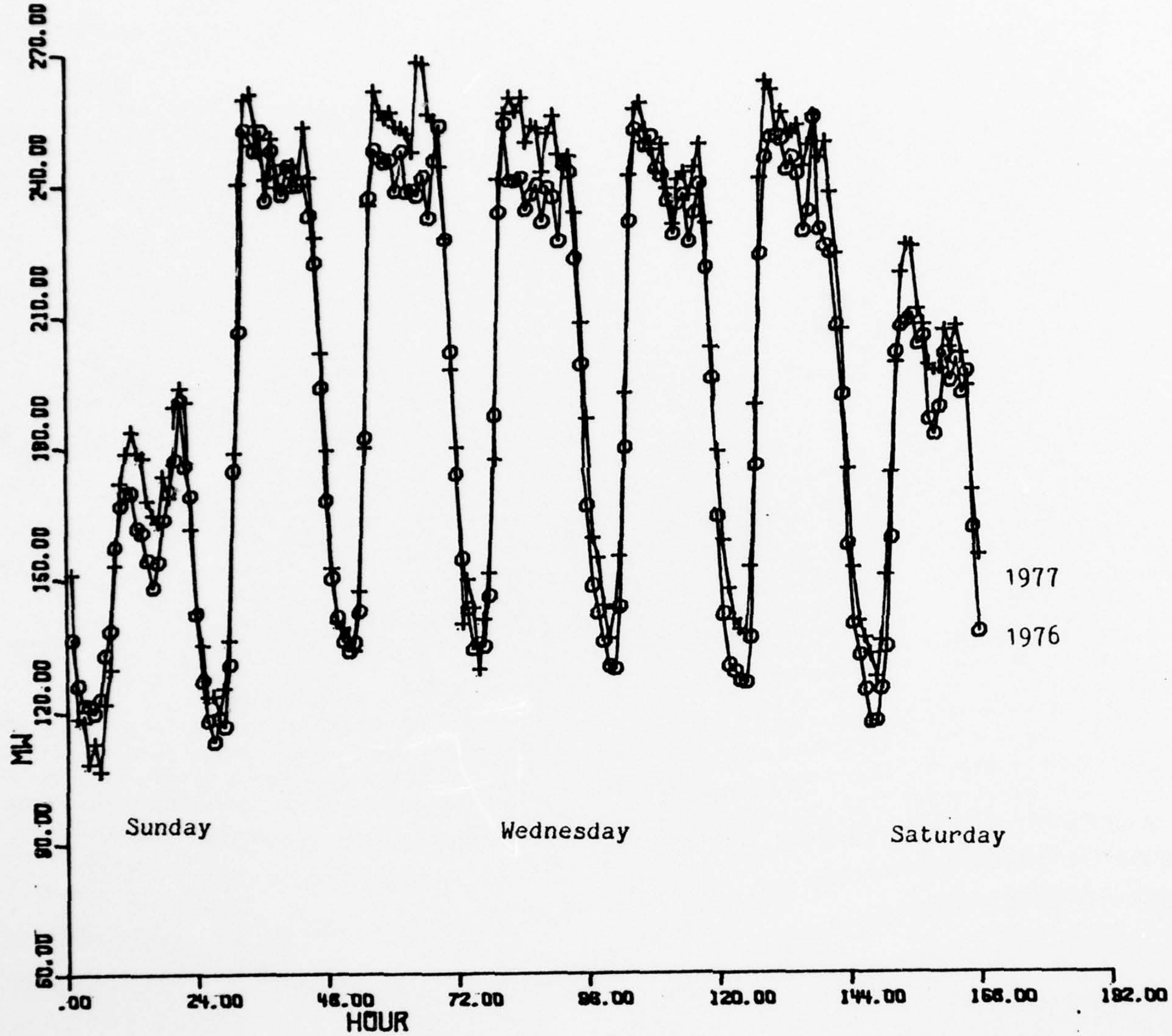


Fig. 5 Loads for 2d Week of Sept. 1976 & 1977

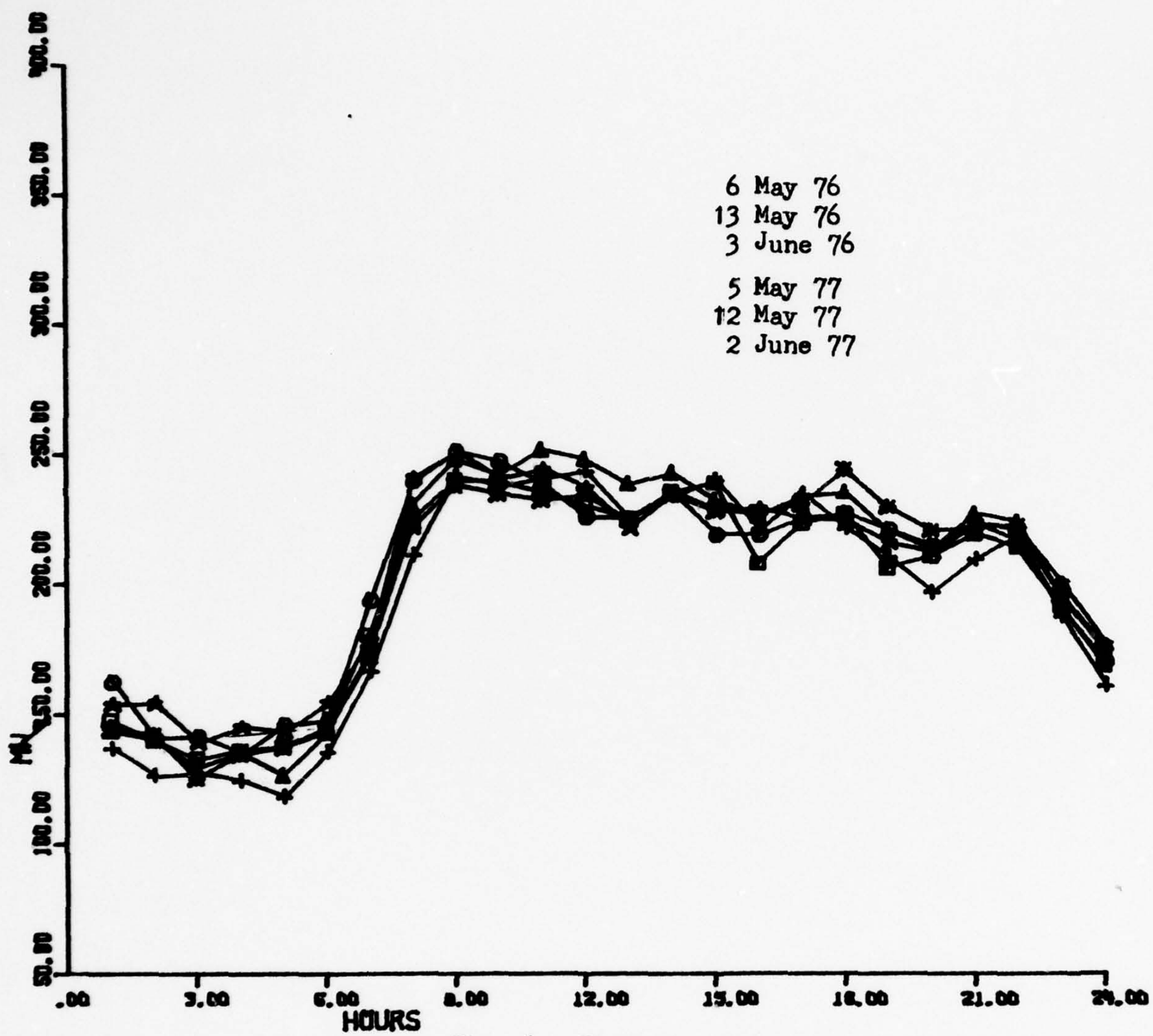


Fig. 6 Thursdays Separated by N Periods

I. 4.5 Peak Day Pattern

Fig. 7 shows the load pattern for the Central Vermont Public Utility system peak day, Tuesday, 18 January 1977. Also shown is Tuesday 16 August 1977 to illustrate the seasonal load variation in total daily load from 8036 MW in January to 4987 MW in August. Average temperature on the peak day was -5° F versus 69° F on 16 August 1977. Vermont is definitely a winter load peaking state as opposed to the New York megalopolis which has an air conditioning summer peak.

The variation in load from season to season is in general due to the length of day and weather, and this factor in turn directly impacts on the customer's consumption patterns. For example, in the winter electric heating and indoor cooking increase as do lighting loads due to shorter days. Plant shutdowns for vacation are rare in the winter and combined with their need for electric heating increase the industrial system load. Alternatively during the summer refrigeration loads increase, lighting loads decrease, and people generally spend less time inside. Industrial loads decrease due to vacation schedules. Summer peaking will not occur in Vermont because the ski industry and heating consume so much electricity.

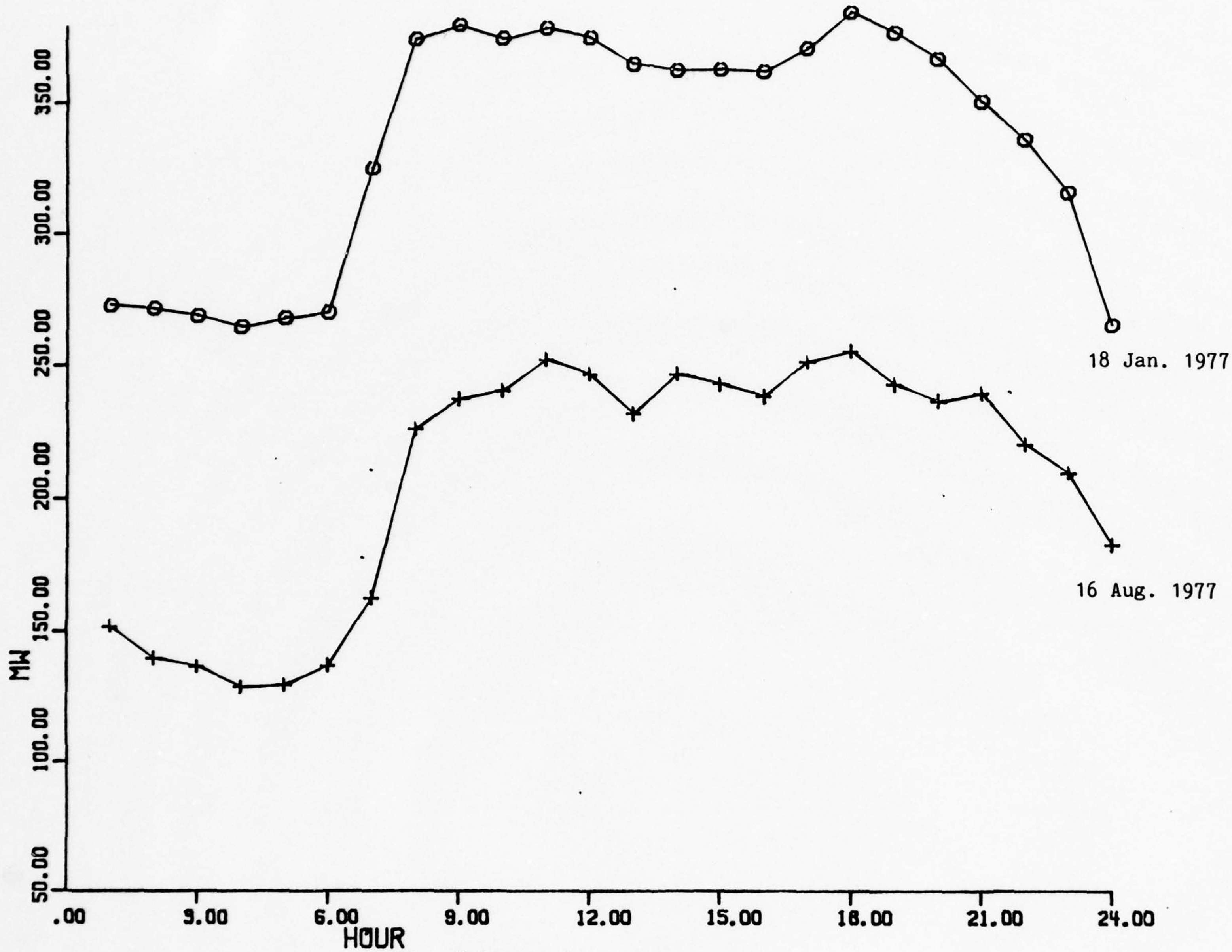


Fig. 7 High and Low System Loads

CHAPTER II

ANALYSIS

II. 1.0 Introduction

The method of load data collection and other available data sources are discussed. Standard statistical analysis techniques are applied to system load data to determine which variables are significant. System load relationships with temperature, (i.e. lag and proportionality) are examined.

II. 1.1 Utility Load Data

Data for this study was made available by Central Vermont Public Service Corporation at their Rutland headquarters. The system dispatcher maintains a handwritten hour by hour log of system loads, weather in Rutland, and operating status on desk sized ledger sheets. These in turn are bound and constitute the legal historical operating record of the utility. Two years of this data was copied, formatted and entered on the University of

Vermont Computer System. The Julian Data Numbering System was chosen to organize the individual daily files of hourly data (Appendix 1). The entire data set consisted of over 17,500 records organized by day as shown (Appendix 1). This data had not previously been available for computer analysis.

II. 1.2 Weather Forecasts

While not all load prediction schemes in the literature use weather forecasts, all actual forecasting employs a weather factor. The accuracy of weather forecasts will be a limiting factor in any load prediction scheme. The National Weather Service is able to provide twenty-four hour forecasts of the maximum and minimum temperatures within two degrees Fahrenheit more than 95% of the time. Their prediction will include a temperature profile which indicates whether there will be a morning low and afternoon high or the converse shape. Approximately 90-95% of the days of a year follow the morning low evening high temperature pattern. Specific hourly temperature forecasts are not currently available. While commercial weather forecasting bureaus claim to provide a more accurate or 'better' forecast the experience of New England Power Exchange (NEPEX) has not supported this claim. NEPEX no longer subscribes to a

private weather service. Other parameters such as wind or cloud cover are not available on an hourly basis with any degree of accuracy. A major limiting factor in load forecasting is the quality and quantity of weather information since all that is reliably available is a forecast of tomorrow's maximum and minimum temperature.

II. 1.3 Consumption Patterns

Extensive work has been done (The Vermont Load Study, 1975) catagorizing consumption patterns of various components of the electrical system load. Germane to this study is the result that power consumption in electrically heated homes slightly leads the total system load throughout a twenty-four hour period. Fig. 8 illustrates this point and also shows that the heating load has no dead spots or zero hours. On the average this allows the system load curve to be decreased by some constant factor for each hour of controlled operation.

A 1975 study (Veno, 1975) of the economic viability of TES units in the Central Vermont Public Utility areas concluded that a peak day load factor improvement approaching 18% was possible by scheduling TES units from 8pm to 6am.

VERMONT LOAD STUDY
GROUP II - RESIDENTIAL
(SPACE HEATING CUSTOMERS)
AVERAGE WEEKDAY HOURLY LOADS - JANUARY 1975

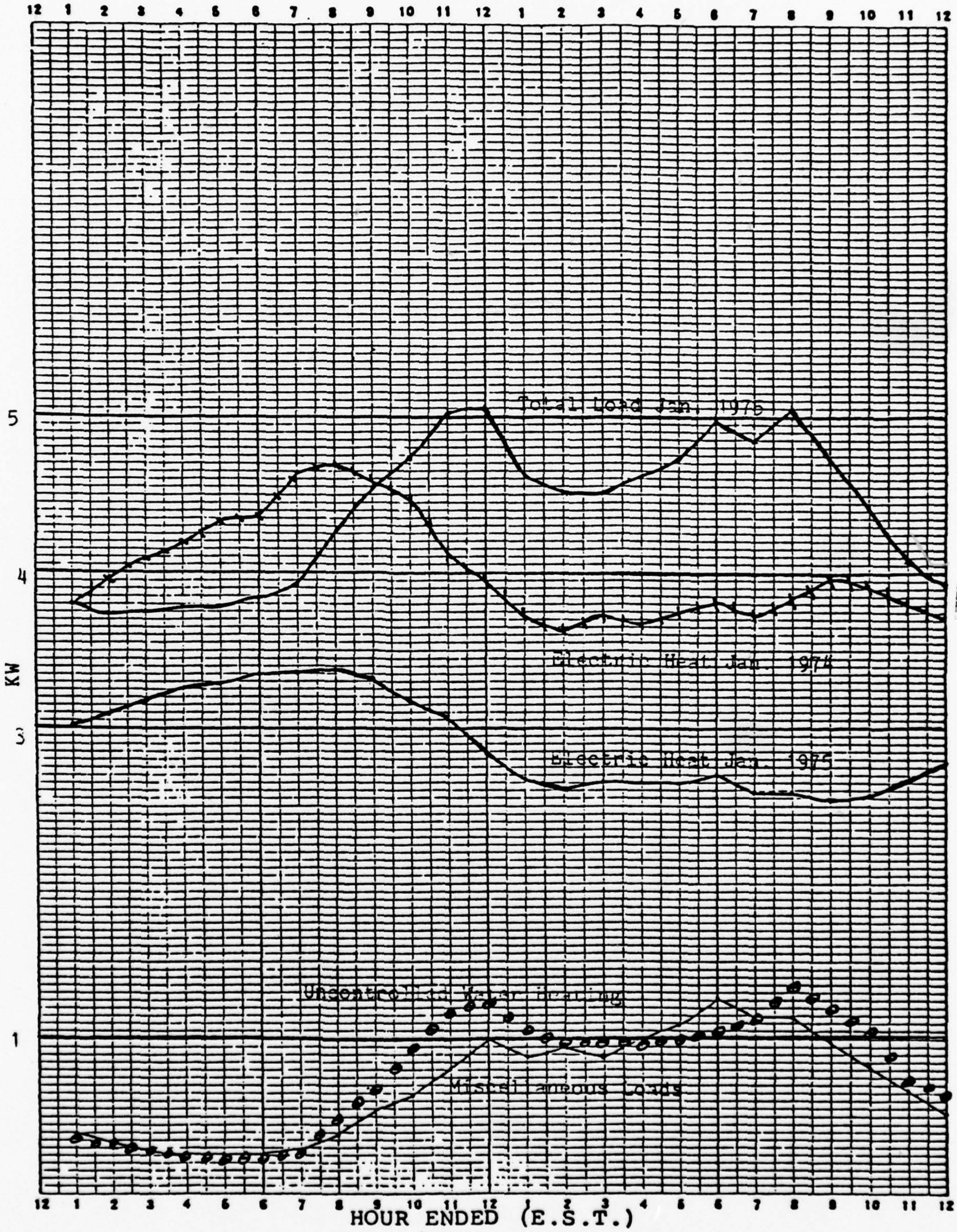
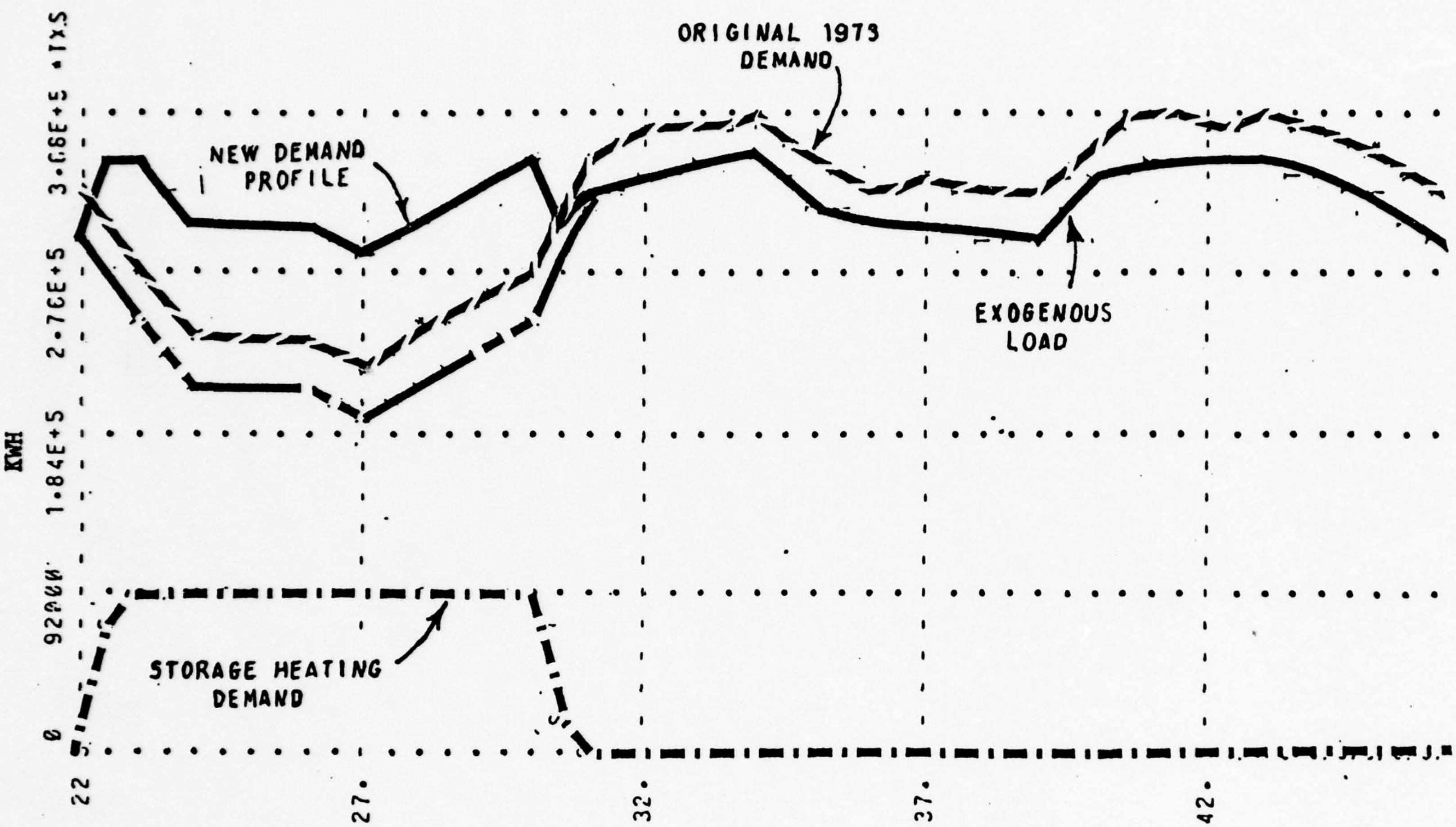


Fig. 8

In that study no provision was made to forecast the loads or consider varying hourly heating consumption. A constant MW value determined by the number of electric heating customers and average installed heating capacity was subtracted from the observed peak day hourly load. The corresponding TES load was then scheduled during the nighttime valley. Fig. 9 illustrates the procedure. The concept of subtracting an average load due to electric heating from the daily load curve will also be employed in this study.

II. 2.0 Data Analysis

A series of analyses were performed on data files using the Statistical Package for the Social Sciences (SPSS). The first objective was to determine the relative strength of relationships among the variables, and the second was to employ standard linear regression analysis as a forecasting technique.



HOUR

Fig. 9 Veno TES Procedure

II. 2.1 Correlation

Initial statistical tests were performed for a given month of the year, day of the week and hour of the day, considering the following as potential variables:

System Load MW

Temperature Fahrenheit

Cloud Cover

Wind Speed

For the month of October 1977 scattergrams were obtained relating system load to temperature for all 30 days. There was no discernible trend. For the same data a scattergram relating MW to hour of the day produced a band whose shape resembled a daily load curve.

The Kendall and Spearman Correlation Coefficients were generated for October 1977 system load (MW) with temperature, wind, cloud cover, and hour of the day as variables:

	MW-TEMP	MW-HR	MW-CLOUD	MW-WIND
Kendall	.1378	.2686	-.0041	.1582
Spearman	.2176	.4567	-.0089	.2088
Significance	.001	.001	0.4	.001

TABLE 1 Correlation Coefficients

Both correlation methods show that load is most dependent on hour of the day, however whether wind or temperature is the second strongest independent variable is not clear. The correlation of load with cloud is not significant probably due to the weather coding scheme employed for cloud cover which reduces a large range of data into a relatively small number of catagories (Appendix 1).

The Pearson Correlation Coefficients for October 1976, are presented in Table 2.

	MW	HOUR	TEMP	CLOUD
MW	1.0	.4823	.0344	.0254
HOUR	.4823	1.0	.175	-.034
TEMP	.0344	.175	1.0	.054
CLOUD	.0254	-.0342	.054	1.0
WIND	.106	.0159	.008	.1123

TABLE 2 Pearson Correlations

II. 2.2 Hourly Correlations

One would specifically expect an inverse correlation between temperature and system load during the winter in a state like Vermont. To produce a valid relationship between system load and temperature it is necessary to remove life cycle affects from the data. Hence each of the twenty-four hours was treated as a separate variable and correlations performed for that hour between MW and temperature. Results of hourly correlations for each of six monthly time periods are presented in Table 3.

Correlation squared (r^2) indicates the proportion of variation in system load explained by temperature (i.e. for October 1976 at 1AM $r = -.618$, $r^2 = .382$), and thus 38% of the variation in load is explained by linear regression on the temperature variable alone. All coefficients listed are significant at the .001 level.

Examining partial correlations, or the relationship between two variables while adjusting for the effects of other variables, led to the conclusion that for October 1977 system loads, the hour of the day is the predominant independent variable followed by temperature, then much weaker cloud cover and finally wind speed. In the regression analysis performed the r^2 change due to cloud was less than .002 while that for wind was less than .0005. The load forecaster at NEPEX had stated that cloud cover was more significant than wind to his system load (Wernhof, 1977).

REGRESSION

HOUR	OCTOBER 1976 COEFFICIENTS A	B	CORRELATION	OCTOBER 1977 COEFFICIENTS A	B	CORRELATION
1	197.15	-.982	-.618	185.6	-.427	-.255
2	184.31	-.896	-.591	166.78	-.285	-.177
3	181.08	-.916	-.633	174.5	-.508	-.508
4	182.49	-.970	-.682	170.3	-.493	-.401
5	189.0	-1.125	-.699	190.92	-.918	-.639
6	207.64	-1.26	-.79	193.22	-.624	-.568
7	249.35	-1.364	-.821	240.5	-.842	-.603
8	314.31	-1.59	-.889	309.4	-1.08	-.584
9	326.3	-1.37	-.898	330.18	-1.05	-.754
10	327.24	-1.33	-.859	314.04	-.739	-.389
11	318.23	-1.135	-.932	358.35	-1.63	-.782
12	319.28	-1.21	-.857	358.95	-1.63	-.688
13	302.99	-1.08	-.839	345.6	-1.57	-.805
14	305.12	-1.00	-.814	336.84	-1.37	-.712
15	300.83	-1.107	-.85	327.15	-1.308	-.830
16	286.17	-.973	-.785	328.04	-1.396	-.858
17	298.35	-1.084	-.784	325.16	-1.29	-.787
18	307.76	-1.114	-.761	343.18	-1.51	-.743
19	313.84	-1.225	-.844	319.56	-1.05	-.634
20	305.0	-1.08	-.777	288.27	-.545	-.333
21	290.84	-.9989	-.753	269.76	.372	-.165
22	276.79	-1.02	-.742	286.82	-.958	-.508
23	257.24	-1.09	-.749	254.52	-.797	-.530
24	224.87	-1.02	-.805	213.8	-.458	-.299

TABLE 3 Regression & Correlation

JANUARY 1976 / FEBRUARY 1976

HOUR	JAN 1976 COEFFICIENTS A	B	CORRELATION	FEB 1976 COEFFICIENTS A	B	CORRELATION
1	260.55	-1.68	-.796	242.55	-1.45	-.84
2	248.05	-1.7	-.85	233.9	-1.54	-.88
3	242.13	-1.69	-.865	234.5	-1.7	-.90
4	240.66	-1.61	-.834	227.33	-1.55	-.89
5	238.9	-1.71	-.84	228.74	-1.53	-.896
6	250.66	-1.76	-.79	217.6	-.566	-.41
7	279.3	-1.5	-.57	263.0	-1.29	-.53
8	313.0	-.77	-.31	284.96	-.558	-.229
9	325.7	-.55	-.25	327.5	-1.48	-.496
10	337.1	-1.08	-.41	336.97	-1.61	-.639
11	335.6	-.87	-.34	309.7	-.578	-.28
12	332.99	-.75	-.30	332.5	-1.44	-.65
13	318.32	-.59	-.28	316.5	-1.17	-.67
14	313.8	-.341	-.147	310.78	-1.15	-.52
15	297.66	-.017	-.007	303.4	-1.14	-.52
16	300.48	-.372	-.175	298.8	-1.19	-.53
17	316.76	-.316	-.148	308.24	-1.28	-.57
18	345.86	-.765	-.382	339.4	-1.78	-.72
19	340.76	-.836	-.498	331.4	-1.24	-.53
20	339.4	-1.11	-.582	331.44	-1.49	-.58
21	331.47	-1.24	-.668	323.75	-1.63	-.73
22	312.76	-1.00	-.598	313.5	-1.85	-.82
23	307.57	-1.84	-.74	291.9	-1.74	-.81
24	275.8	-1.33	-.706	265.5	-1.61	-.83

JANUARY 1977 / FEBRUARY 1977

HOUR	JAN 1977 COEFFICIENTS A	B	CORRELATION	FEB 1977 COEFFICIENTS A	B	CORRELATION
1	245.85	-1.49	-.614	253.3	-2.15	-.878
2	234.6	-.989	-.46	237.1	-1.9	-.87
3	228.8	-1.19	-.579	231.7	-1.87	-.89
4	224.36	-.56	-.37	230.1	-1.75	-.77
5	225.3	-.624	-.479	226.4	-1.49	-.72
6	233.6	-.474	-.418	224.8	-.65	-.40
7	269.8	-1.18	-.40	257.0	-.728	-.344
8	307.3	-.21	-.098	295.9	-.47	-.183
9	327.2	-.62	-.175	348.6	-2.66	-.66
10	323.0	-.238	-.069	350.98	-2.56	-.62
11	339.2	-1.59	-.365	356.5	-2.54	-.606
12	334.4	-1.09	-.285	356.9	-2.5	-.653
13	324.95	-1.16	-.333	341.6	-2.2	-.66
14	290.8	+.752	+.175	356.6	-2.8	-.643
15	302.7	-.389	-.08	337.7	-2.38	-.57
16	309.2	-1.07	-.28	331.6	-2.29	-.59
17	320.0	-.81	-.23	341.4	-2.5	-.64
18	346.8	-1.02	-.285	363.6	-2.6	-.72
19	341.6	-.835	-.278	360.9	-2.3	-.72
20	332.7	-.52	-.314	346.9	-2.1	-.72
21	326.04	-1.03	-.365	335.6	-2.02	-.73
22	302.3	-.196	-.133	317.4	-2.06	-.795
23	288.2	-.995	-.38	292.7	-1.92	-.727
24	262.6	-1.12	-.485	264.4	-1.7	-.75

TABLE 3 Regression & Correlation

These r^2 values are so small that the corresponding variables do not affect the load. Hence as an initial forecasting methodology neither cloud cover nor wind will be included in the prediction routine.

II. 2.3 Heating Lag

The existence of a lag between temperature change and system load change has been postulated (Hajdu, 1977). For a temperature change the lag, when it exists is between four to eight hours, and is attributed to heat storage or inertia in massive buildings such as would be common in large city loads.

As a method of identifying the lag of Central Vermont Public Utility's load five Wednesdays in March 1977 were plotted in Fig. 10 and Fig. 11. While the inverse relationship between temperature and system load is evident there does not appear to be a lag affect. Points where the daily temperature profiles cross closely correspond to load profile crossings. The conclusion is that Central Vermont does not have a time lag between system load and temperature change.

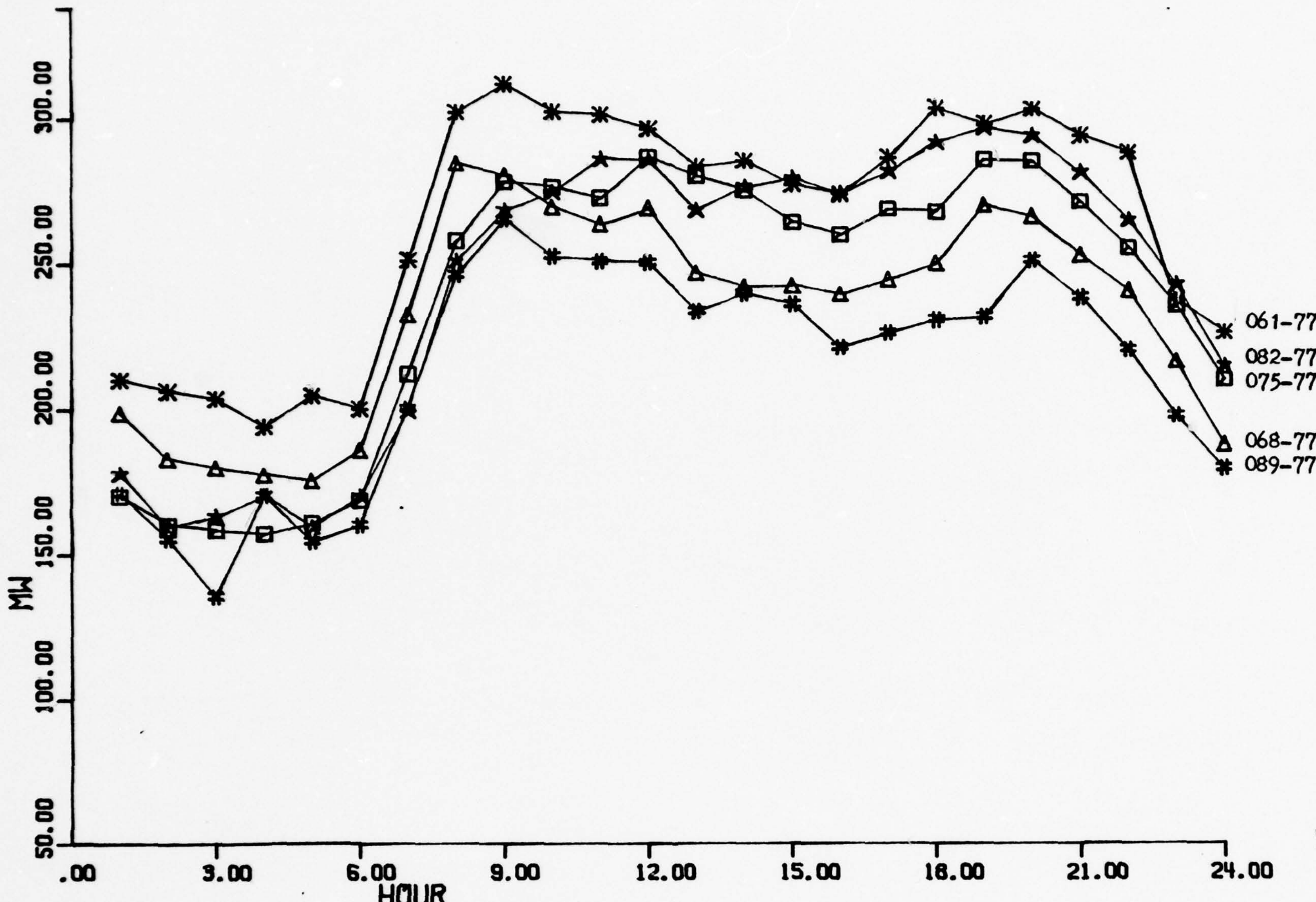


Fig. 10 System Load March Wednesdays 1977

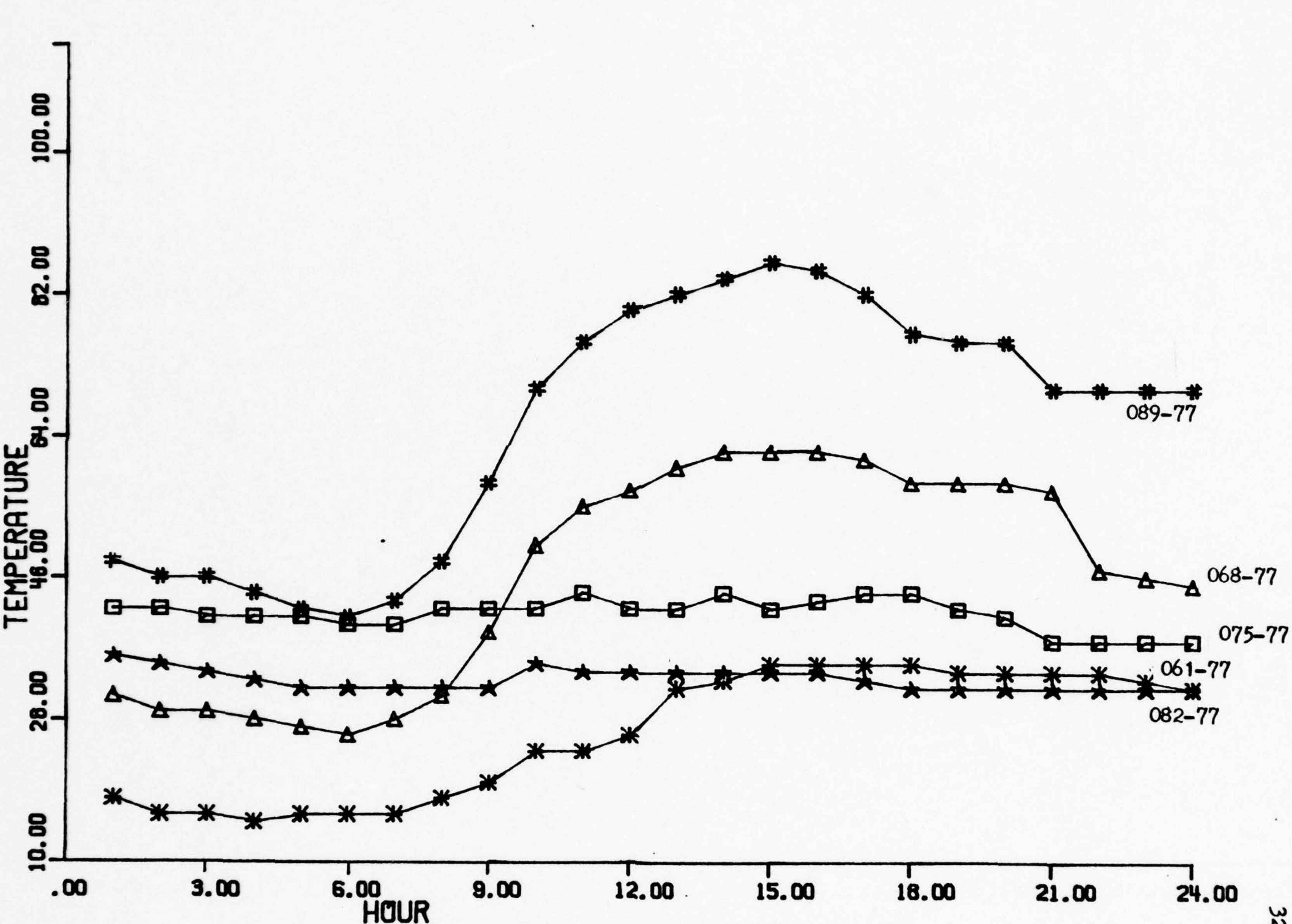
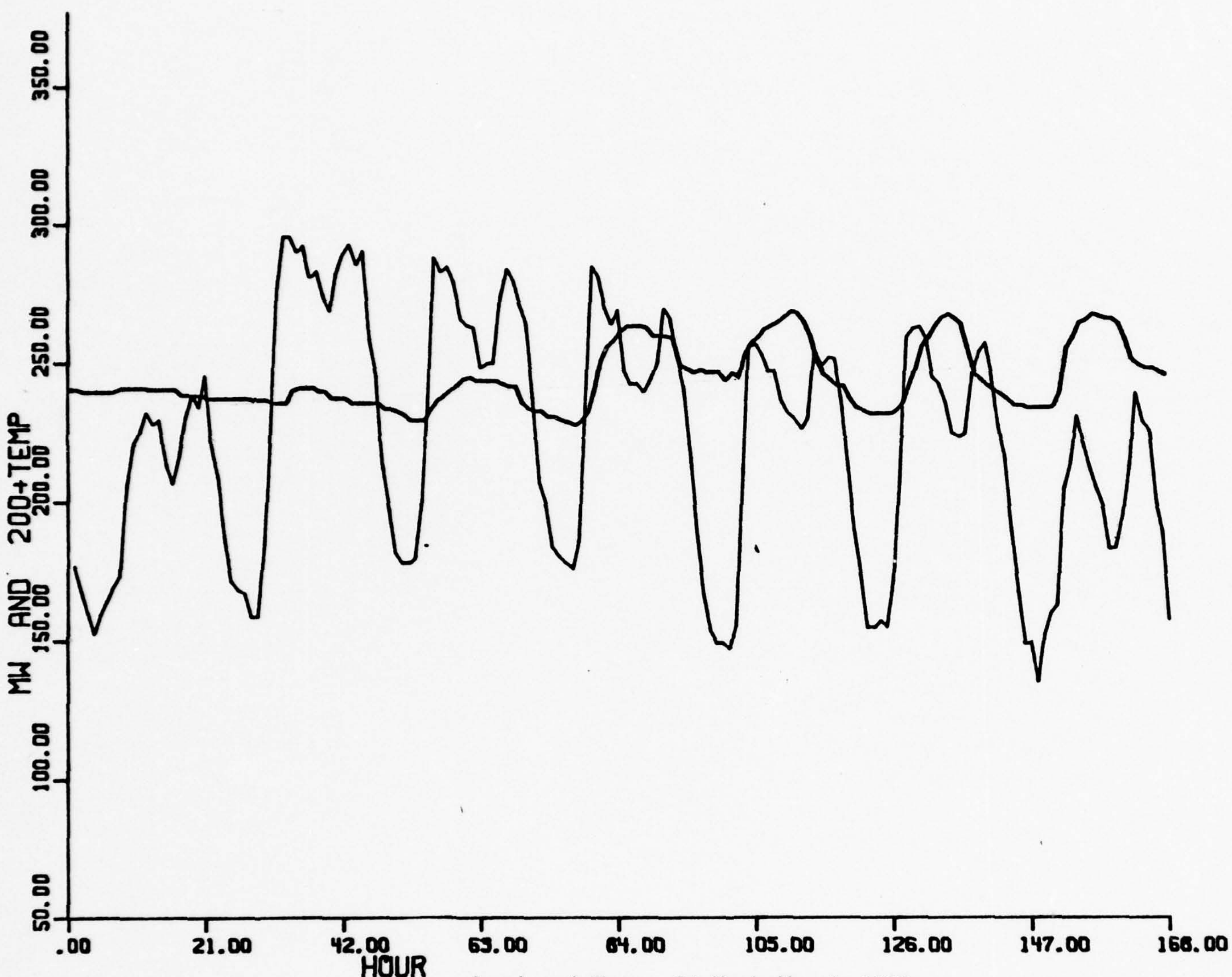


Fig. 11 Temperatures March Wednesdays 1977

II. 2.4 Temperature Affects

The inverse relationship of temperature and MW can be clearly seen in Fig. 12 which shows both the hourly system load for the second week of March 1977 and the hourly temperature. By comparing the slope of the temperature with the increasing load an approximate relationship is evident. March loads increase approximately one megawatt for each one degree drop in temperature.

Fuel oil companies commonly use a degree day measure to determine when additional fuel deliveries are required. The degree day is a measure of the declination of the mean daily outdoor temperature from an arbitary neutral comfort level of 65 degrees. Positive degree days, temperature less than 65°, generally mean that energy is being used for heating. While not commonly used, negative degree days partially measure air conditioning requirements, neglecting humidity. Degree days are a post hoc measure of the temperature profile, and because of this they are not used in forecasting electric loads (Wernhof, 1978).



Load and Temp. 2d Week March 1977

Fig. 12

CHAPTER III

PREDICTION METHODS

III. 1.0 Introduction

Several methods of system load modeling and forecasting are examined and these methods are applied to develop a model for Central Vermont Public Service Corp. A simple hybrid forecasting algorithm is developed and found to yield acceptable results, and a computer program implementing the algorithm is presented.

III. 1.1 Catagories

Historically, when individual utilities controlled their generating resources and made their own daily load forecasts, the prediction was based on years of operating experience. The method then used to arrive at a forecast was an extrapolation of past system load experience manually correlated or modified by the weather prediction. The correlation criteria, while subjective, were dynamic and could be complex. Due to the lack

of a fixed mathematical methodology, consistent forecasts for the same criteria were not possible. This did not mean that the operator produced forecasts were invalid. In fact, Hydro Quebec, which is reputed to have one of the best prediction schemes in use, relies on an operator's judgement to fine tune the computer produced forecast for weather affects (Bechard, 1978). New England Power Exchange (NEPEX), a scheduling entity whose peak hour demand is approximately 16,000 MW, relies solely on the operator technique (Wernhof, 1978). Results obtained with an operator's forecast range from 5 to 10% average error over a twenty-four hour period, and as mentioned earlier, several utilities which had experimented with mathematical forecasts have returned to the operator method (Galiana, 1975).

The forecasting method employed should logically be related to the type of forecast required. What does the utility need to know in the future? Is it the next day's hourly load, only the peak load, total daily energy supplied, the system load at a specific hour for system maintenance or only loads for security purposes? The same criteria which answer these questions should be used to judge the results of a forecasting method. Judging an hourly forecasting procedure by comparing the total actual daily load with the summation of 24 hourly forecasts is not an adequate

indicator of hourly accuracy (Bechard, 1978).

Mathematical models for the load are divided into three broad catagories depending on the inclusion of a weather forecast variable (Galiani, 1975). These are:

1. Models which include weather effects but do not rely on the latest load behavior for the forecast.
2. Models which rely on time of day and latest load data.
3. Models which include weather, time of day and immediate past load in the forecast.

Arguments have been made for the validity of each model type, but by inspection Model 3 is most general since it includes the largest number of available data inputs.

III. 1.2 Time-Series Models

The most frequently encountered model based entirely on prior loads, in the literature on load forecasting, is the time-series model. Since the late 1960's the Box-Jenkins approach has dominated time-series investigations. A time-series is used to fit the observations of system load made at discrete hourly time intervals. The method relies on the premise that the load curve has a recognizable shape which is periodic and which will repeat

itself in the future to fit a function of time to the load. The time-series approach normally does not afford greater weigh to the most recent load, except by reestimating the series coefficients frequently. This seems to be a serious drawback to the time-series approach due to the computational requirements of reestimation.

The Box-Jenkins method for modeling a time-series has three steps: 1) identification, 2) parameter estimation, and 3) diagnostic forecast checking. In the identification process the sample autocorrelation is the prime indicator of the order of differencing required to achieve a stationary series. It measures the correlation between K periods of the time-series an is computed by

$$\frac{\sum_{t=1}^{n-k} (Z_t - \bar{Y})(Z_{t-k} - \bar{Y})}{\sum_{t=1}^{n} (Z_t - \bar{Y})}$$

$\bar{Y} = Z - \bar{Z}$ = average deviation

$\bar{Z}$ = mean of series

n = number of observations on series

k = number of periods between observations

Z = observation value (MW) from series

Autocorrelations for the new series were examined to determine which ARIMA model should be initially tested. Characteristic graphs of autocorrelations (Mabert, 1975) were compared with experimental results to estimate the series order.

Partial autocorrelation is then used to further refine the identification of a model. It measures the strength of the relationship between time periods in a series.

$$\frac{\left[\text{Autocorrelation}\right]_k - \sum_{j=1}^{k-1} A_{k-1,j}\left[\text{Autocorrelation}\right]_{k-j}}{1 - \sum_{j=1}^{k-1} A_{k-1,j}\left[\text{Autocorrelation}\right]_j}$$

$$A_{kj} = A_{k-1,j} - A_{kk}\, A_{k-1,k-j} \qquad j=1,2\ldots k-1$$

During the next step of the Box-Jenkins method, estimates of the coefficients are determined by the method of least squares. For a second order autoregressive model

$$Z_t\,(\hat{\phi}_1,\hat{\phi}_2) = \sum_{t=1}^{n}(Z_t - \hat{Z}_t)^2$$

$\hat{\phi}_i$ = autoregressive coefficient, i=1 to order of model

Z_t = observed series value at time t

$\hat{Z}_t$ = forecast series value at time t

is minimized. The computational procedure involved uses the identified autoregressive model to forecast the load $\hat{Z}$ for each known observation in the time-series Z(t). The non-linear routine then calculates the forecast error at each point and selects the set of ϕ_i which minimize this error. Finally the model is checked for adequacy of fit by using a chi-square test, Q.

$$Q = n \sum_{k=1}^{k} r_k^2 (\hat{a})$$

n = total number of observations

k = number of residual autocorrelation values

$r^2 (\hat{a})$ = residual autocorrelation of a at lag k

If the computed value of Q is greater than tabulated χ^2 it indicates that the model should be rejected at that confidence level. The IMSL computer program routine used provided the significance level of the chosen model directly.

III. 1.3 Time-Series Forecasts

The computer program (Whitmore, 1977) was used extensively to fit a time-series model to CVPS's load data. Working initially with one months hourly data, weekends removed, the 24th difference was taken to reduce the data to a stationary series.

$$Y_t = Z_t - Z_{t-25}$$

This produced an autocorrelation of uniformly small autocorrelation values for increasing time lags. High autocorrelation was observed at k = 1 and 24. K = 168 hours, one week, was another expected high autocorrelation. The autocorrelation exhibited an exponentially damped cosine pattern characteristic of an autoregressive model with no spiking to suggest a moving average component. Applying the principle of parsimony no further modification was made to the series. The Box-Jenkins methodology led to the identification of a second order autoregressive model from the partial autocorrelation vector as shown in Fig. 13. The differenced model form which these values fit is:

$$\nabla d\hat{Z}(t) = a_t + \sum_{i=1}^{p} \phi \nabla dZ_{t-1}(t) - \sum_{i=1}^{q} \theta_i \; a_{t-i}$$

PARTIAL AUTOCORRELATION VECTOR:

1	.8975
2	-.4708
3	-.1579
4	-.1998
5	-.0437
6	.1002
7	.0074
8	.0119
9	-.0366
10	-.1721
11	-.2186
12	-.0642
13	.0607
14	-.0552
15	-.1720
16	-.0218
17	.1488
18	.2231
19	.1333
20	.1001

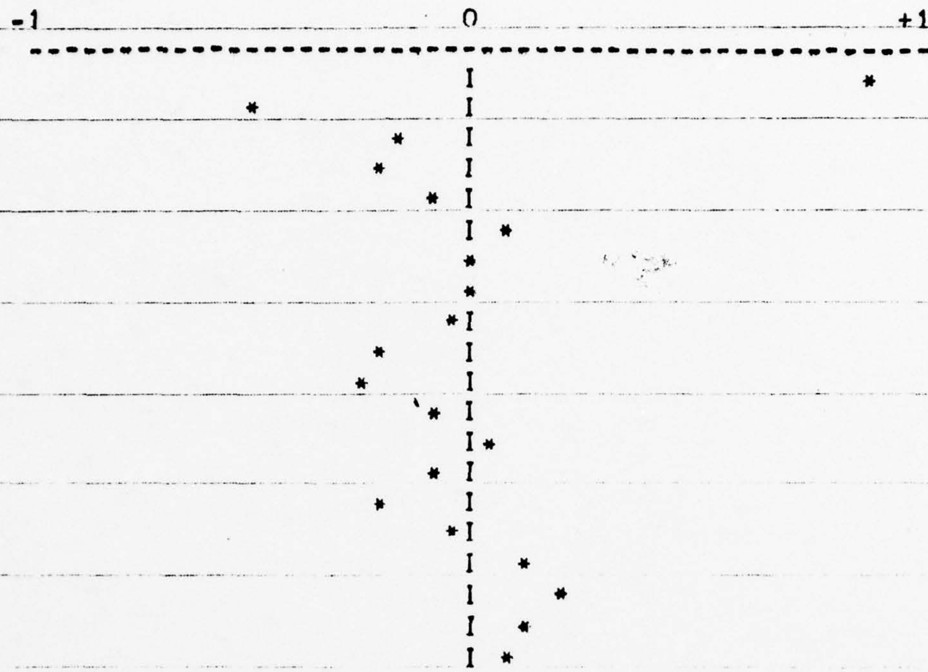


Fig. 13 Partial Autocorrelation

Reducing this to a second order undifferenced autoregressive formulation yields:

$$\hat{Z}(t) = Z_o(t) + \sum_{i=1}^{2} \phi_i Z_{t-1}(t)$$

Computationally the algorithm iterates first on the moving average parameters, then on the autoregressive parameters and finally on the differences. Moving average and difference operation were fixed to be zero. Hence a 2nd order linear system gives estimates of ϕ_i from $Z = \phi_i Z$. Then a Gaussian White Noise Test is performed on the forecasting errors $\hat{Z}$. If these errors pass the specified model significance the model is accepted, otherwise, the program loops and reestimates ϕ_i. Results of a typical forecasting run at the .02 confidence level are listed in Table 4.

Of the numerious trial runs performed none yielded

TIME-SERIES FORECAST

Constant = 1.388
Autoregressive Parameters = .2165 & .4073

HOUR	FORECASTS	FORECASTED SERIES	MAX. FORECAST ERROR AT .02 CONFIDENCE LEVEL
1	12.28	-27.03	20.35
2	9.83	-4.67	20.82
3	8.52	-10.37	22.78
4	7.24	10.34	23.10
5	6.43	-14.36	23.55
6	5.73	.91	23.69
7	5.25	-16.89	23.81
8	4.86	-5.32	23.86
9	4.58	-10.07	23.90
10	4.36	7.64	23.91
11	4.19	5.83	23.93
12	4.07	-10.90	23.93
13	3.98	5.35	23.94
14	3.91	-15.89	23.94
15	3.85	-11.61	23.94
16	3.81	-22.33	23.94
17	3.78	-12.01	23.94
18	3.61	-30.70	23.94
19	3.74	-3.27	23.94
20	3.73	-22.30	23.94
21	3.72	4.42	23.94
22	3.71	-9.78	23.94
23	3.71	-7.65	23.94
24	3.70	5.98	23.94

TABLE 4 TIME-SERIES FORECAST

satisfactory predictions for more than four to six hours in the future as can be inferred from Table 4. The time-series works best for short lead periods, and this inherent limitation has been observed by others (Anderson, 1976). In this case it is probably due to weather affects which are not included in the time-series formulation.

III. 1.4 Frequency Domain

It is interesting to observe that due to the periodic nature of the basic system load it could be modeled by a harmonic series. In the frequency domain the load exhibits peaks at multiples of 24 hours and 168 hours (one week). A Fourier analysis would give:

$$\hat{Z}(t) = Z_o + \sum_{i=0}^{n} a_i \sin(iwt) + b_i \cos(iwt)$$

with $w = 2\pi/168$ for the fundamental (weekly) frequency. The problem then is to estimate the coefficients for a set of harmonics, less than 84, the Nyquist Limit, so that the periodic function is adequately approximated. Filtering techniques have

utilized many approaches, but exponential smoothing and Kalman filtering are the most common (Gupta, 1972; Sharma, 1974). Other than providing a more elegant mathematical approach the variations on a harmonic series model do not claim to produce average accuracies below 4% or 5%. It is also apparent that the operating branch of the power companies are reluctant to use a more complicated forecasting method than the basic operator's prediction. Other than verifying the frequency spectrum of Central Vermont Public Service Corporation's load through autocorrelation, Section III. 1.2, no further investigation into Fourier analysis and modeling was conducted.

III. 1.5 Linear Models

The operator's forecasting method determined a basic load shape from years of experience. Often merely the last day's or a similar prior day's load curve constituted the basic load shape model. If the weather remained constant then the basic load shape became the predicted load. If forecasted weather differed from a prior similar day then the basic load shape had to be modified. Operator forecasting is an art without written methodology.

The operator's basic procedure generated a linear model of the form

$$\hat{Z}(t) = Z(t) + B(w)$$

$\hat{Z}(t)$ = Predicted load

$Z(t)$ = hourly component from prior similar day

$B(w)$ = correction factor function of weather

It is then reasonable to postulate a model which shifts Z (t) by an amount inversely proportional to the difference in temperature. But what is meant by the temperature difference? Average temperature difference might be a better measure, however small. The weather service can not provide as accurate a short term forecast of average temperature as it can of maximum and minimum temperature.

The constraint of available forecasted temperature information indeed impacts on the model selected. If a temperature model is chosen to follow the normal pattern of morning low followed by an afternoon high and the forecast is also for a morning low afternoon high, then the total model could logically be decomposed into two parts. The morning segment from

(0001 - 1200 hours) dependent on morning low temperatures, and the afternoon segment dependent on the high forecasted temperature.

Initially then a linear model might be:

$$\hat{Z}_1\ (t) = Z'\ (t) + B_1$$

$$\hat{Z}_2\ (t) = Z'\ (t) + B_2$$

Z' = prior similar days load for hour t

B_1 = (base day AM low temp. - forecasted low temp.)

B_2 = (base day PM high temp. - forecasted high temp.)

This formultion implicitly assumes that the load will change at a constant rate or gain factor of one megawatt per degree Fahrenheit for all hours of the day and year Fig. 12, Section II. 2.4.

Using the two years of available data, results of trial simulations produced average errors ranging from 5 - 10%. Actual

maximum and minimum temperatures were used for these simulations, and the results were encouraging when considered in the context of simplicity of procedure. On the basis of total daily load, these forecasts were equivalent to those obtained by more sophisticated techniques in commerical practice (Bechard, 1978).

To refine the linear model into a dynamic one and at the same time make the gain constants more realistic, gain factors were computed for each hour from the previous two similar days. This formulation computed:

$$G_i = \frac{\Delta \text{ MW } (t_i)}{K + \left| \Delta \text{ Temp } (t_i) \right|}$$

G_i = sensitivity of load with temperature

MW = change in system load at hour t

T = change in temperature at hour t

K = unity constant

Provision was made to prevent the denominator from becoming zero by adding in a small constant. The linear model equation then became:

$$Z(t) = Z'(t) + G_i(t)\,B(t)$$

Again tests were run on Central Vermont data. In many cases the hourly results were better than had been observed with $G_i = 1$. However in a significant number of samples a larger forecast error was produced. These large errors corresponded to large (i.e. >3) values of G_i. The absolute value of G_i was then constrained less than or equal to 3 with a marked improvement in average results. Further improvements were noted experimentally as G_i was reduced to a limit of 1.5. Beyond this value prediction accuracy again fell off. Experimentally the limiting value of 1.5 was found to optimize forecasting accuracy with this algorithm for the two years of data examined.

However merely constraining the gain did not insure that the G_i which had not been limited were optimized in a systematic fashion. Recall that G_i was merely the ratio of change in system load to change in temperature at time t on two previous similar days. While this forecasting procedure produced usable results as the sample figures and tabulations of Appendix 3 illustrate, for non-winter months, it lacked a formalized statistical basis.

III. 1.6 Regression Prediction

A standard tool used to make forecasts from statistical data is regression analysis. Straightforward least squares fit to historical data merely reproduce in some manner the load function or curve shape which is already known. Least squares approximations alone, as a load forecasting method, produce 8% - 10% average errors (Galiani, 1975). A closer examination of the linear regression methodology from SPSS as discussed earlier, section II 2.2, revealed two possible alternative regression formulations. The first possibility is to perform the regression analysis on each hour of the prior thirty days producing twenty-four regression equations:

$$\hat{Z}(t_i) = A(t_i) + B(t_i)\,\mathrm{Temp}(t_i) \qquad i=1,2\ldots24$$

Then the daily load is merely the summation of $Z(t_i)$. In addition to the necessity of reinitializing constants $A(t_i)$ and $B(t_i)$ frequently, this approach suffered from the practical limit, mentioned earlier, that hourly temperature is unknown.

This equation was modified to fit available temperature forecasts as was done before. The forecasting equations then became:

$$\hat{Z}(t_i) = A(t_i) + B(t_i)\ f_1(T) \qquad i=1,2\ldots12$$

$$\hat{Z}(t_j) = A(t_j) + B(t_j)\ f_2(T) \qquad j=13,14\ldots24$$

$\hat{Z}(t\ )$ = forecasted load for hour ij

$f_1(T)$ = prior day min. temp - forecasted min. temp.

$f_2(T)$ = prior day max. temp. - forecasted max. temp.

Recalling that the basic linear regression equation has the form

$$Y' = A + BX$$

Y' is the estimated value of the dependent variable Y. The constant A represents the Y axis intercept of a best fit line with slope B. It would appear that B is a measure of the gain analogous to G_i of the prior linear formulation section III. 1.5. The variable B for each hour measures the change in Y or

system load with a change of one unit in X, the temperature. Implicitly the sum of squared residuals, $(\sum_K |Y-Y'|^2)$, has been minimized within the SPSS routine which generated A and B from:

$$A_i = \bar{Y} - B\bar{X}$$

$$B_i = \frac{\sum (X - \bar{X})(Y - \bar{Y})}{\sum (X - \bar{X})^2}$$

Where X and Y are mean values. How good would a prediction then be if maximum and minimum temperatures were used instead of hourly values? Table 5 shows daily regression results for October 1976 and October 1977. This entirely SPSS method proved to be a consistently poorer load predictor than did the method of Section III. 1.5

III. 1.7 Regression-Similar Day Method

A third alternative to the basic regression approach is to combine the regression slope constants B with a prediction routine based on the previous similar day. In essence, the B provide a best fit slope for the ith hour prediction from the prior thirty day's observations.

COMPARISON OF FORECAST
METHODS

OCTOBER 1976 AND OCTOBER 1977

Date	Constrained Gains	SPSS Gains **Hybrid**	Entirely SPSS	Constrained Gains	Entirely SPSS
	Average Errors 1976			Average Errors 1977	
1	2.77	2.58	-	3.4	16.25
2	5.62	5.29	20.07	5.57	34.17
3	8.69	7.81	37.18	4.91	4.61
4	4.64	4.67	10.41	3.68	3.52
5	4.76	5.12	5.43	3.19	5.12
6	2.86	3.87	3.39	3.73	5.07
7	2.2	2.4	4.16	3.65	5.75
8	3.71	3.92	2.11	8.68	9.56
9	5.22	5.12	15.94	13.32	16.25
10	6.75	6.39	26.38	4.1	4.3
11	4.18	5.49	6.34	6.22	3.35
12	4.71	3.34	4.01	2.02	--
13	3.51	3.39	4.4	3.58	3.78
14	4.05	2.97	3.61	5.54	4.51
15	3.74	3.59	2.85	8.11	14.11
16	7.5	8.2	--	9.95	25.45
17	9.03	9.83	37.94	4.89	7.26
18	3.68	2.85	6.27	5.76	4.15
19	3.67	2.82	3.3	3.51	2.93
20	5.17	5.39	4.29	3.16	2.77
21	3.17	2.69	4.67	6.19	5.2
22	4.05	4.06	2.23	5.67	19.06
23	9.98	9.40	12.33	7.41	33.84
24	8.94	8.39	--	4.79	3.44
25	3.96	4.66	6.04	4.77	3.97
26	4.21	3.09	3.72	3.89	4.21
27	4.2	4.16	4.6	3.54	4.15
28	3.25	3.30	2.58	3.95	5.75
29	4.4	3.2	4.49		
30	4.83	4.93	17.35		
31	8.01	7.26	30.6		
MEAN	5.01	4.84	10.24	5.26	9.35
STD DEV	2.06	2.09	10.7	2.4	9.14

TABLE 5 Forecasts

Since the B 's are the least squares gains; their use negates the need to constrain the gain term to be less than 1.5. In actuality their range of values is itself limited as can be seen in Table 4. This model is then:

$$\hat{Z}(t_i) = Z(t_i) + G_{ssi}\ f_1(T) \qquad i=1,2\ldots12$$

$$\hat{Z}(t_j) = Z(t_j) + G_{ssj}\ f_2(T) \qquad j=13,14\ldots24$$

$G_{ss} = B_i$ **hourly regression slope**

Comparisons between this hybrid method and that of Section III. 1.5 were performed for several days during the peak months in 1976 and 1977 (Appendix 4). Results were consistently improved, approximately 1%, using the hybrid forecast algorithm for randomly selected days throughout both years. This forecast algorithm combines the statistical coefficient B produced from regression analysis and a functional weighting of the temperature variable with the prior similar day's load curve.

In reality the predicted load is a function of a function. It can be viewed as a function of two variables. One variable is a function of the general load shape for that day of the week and the other variable is a function of temperature. Hence, a model can be no better than the basic function chosen to represent the load curve shape. Regression, time-series, sum of sinusoids all

approach the basic function through a least squares averaging approximation which produces comparable results with considerably greater computational requirements. It can be legitimately argued that the forecast improvement gained with the hybrid over that of Section III. 1.5, is not great enough to offset the added program complexity. Utilities have demonstrated a strong desire to use the simplest routine which will give acceptable results.

Finally judging the three methods on the power industry's standard of total required energy versus total predicted energy each day, all three methods are again similar and equivalent to current industry results (Bechard, 1978).

III. 2.0 Computer Algorithm

The forecasting program written during this study was designed in two independent parts. Part one is a general interactive mainline routine which interrogates the system operator's console. This routine then generates Julian file names of similar days to pass to a prediction subroutine. The prediction subroutines themselves constitute the second part of the forecasting program. This arrangement allowed changes in the prediction parameters to be readily made and at the same time be

transparent to a system operator. Appendix 2 is a source code listing of the forecasting program which has been developed.

III. 2.1 Similar Day Selection

Conceptually the selection of a similar day is trivial, although the similar day load shape plays such a dominant part in the forecast that several different combinations were evaluated. A best fit was found to utilize:

Day to be Predicted	Similar Day for Curve Shape	Similar Day for Hourly Gain
Sunday(A)	Prior Sunday (A-7)	Prior Saturday (A-8)
Monday(B)	Prior Monday (B-7)	Prior Friday (B-3)
Tuesday(C)	Prior Friday (C-4)	Prior Thursday (C-5)
Wednesday to Friday (D)	Prior Day (D-1)	Day before Prior Day(D-2)
Saturday(E)	Prior Saturday (E-7)	Prior Sunday (E-6)

TABLE 6 Similar Days

Logically the prior similar day is the most recent day with the same characteristic shape as the day to be forecast.

III. 2.2 Forecast

Computationally the forecast is generated by treating each day as a 24 component vector. This is based on the prior similar day and modified by a scale factor or Gain operating on the difference between high/low temperature on the prior day and the forecast temperatures. The results remain in a vector format with each element corresponding to an hour. Sample tabular output is in Appendix 3.

CHAPTER IV

LOAD LEVELING

IV. 1.0 Introduction

Historical load factors of Central Vermont Public Service Corp. are examined. Impacts of deferred electric heating on system load factors are considered both with and without load forecasts.

IV. 1.1 Load Factors Central Vermont Public Service Corp.

The term load factor only has meaning when the time period involved is specified. For example, the daily load factor on the peak day in 1976, (23 January) is computed as:

$$\frac{\sum Z_i}{\left[\max Z_i\right] \times 24} = \frac{8132.38}{(386.9) \times 24} = 87.58\%$$

Daily load factors vary considerably throughout the year (Appendix 5). The yearly load factor computation replaces 24 hours by 8,760 hours in both the numerator and denominator, but

the peak hourly term in the denominator does not change.

IV. 2.0 Electric Space Heating

Mean hourly residential electric space heating consumed approximately 3.0 KW/Hr during January 1975 (Vermont Load Study, Chapter 5, 1977), hence daily average energy supplied to each customer is 72 KWH. Therefore, this amount of average energy must be supplied to a TES customer during eight charging hours selected as off peak times from the forecasted load. Assuming each unit is charged at a rate of 9 KW/hour for the eight hours it is turned on, then one thousand customers will produce a 9 MW change in the system load curves during periods of TES operation. The ratio of 3:1 used here is more conservative than the industry charging rate of 2.5.

It is assumed that ripple controlled TES units will predominately be installed in new dwellings as opposed to retrofitting existing homes due to their lower installation cost in new construction.

IV. 3.0 Load Shaping

For a given number, N in thousands, of new controlled TES customers the load forecast curve of Section III. 1.6 or III. 1.7 can first be reduced N x 3 MW at each of the twenty-four hours. This is necessary to account for the impact of these customers' non-deferrable electric load. Then each hour which is forecast some arbitary percentage below the predicted peak is available for operation of TES units. This percentage, assumed for this study as 95%, will be determined by management based upon improvement desired in load factor and confidence in the forecast.

For the purpose of this study an hour is available for TES charging if the forecasted load is less than or equal to 95% of the reduced peak. Then at each available hour, N1, units will be operated to increase system load to the 95% of the predicted peak level. For the peak day in 1977 a simulation was run with 2,000 TES customers. The predicted peak is reduced by 6 MW to 386.4 MW, (actual peak was 384.2MW), and twenty hours of predicted load fell below the 95% level. Now instead of only eight to ten hours available for nighttime TES charging the available charging window has been doubled. With 4,000 customers 18 hours are

available Fig. 14, and daily load factor has been improved to 93%.

The yearly load factor was only slightly improved to 61% due to the summer-winter load differential. Additional improvements to the yearly load factor are possible with larger N, although TES systems capable of storing energy for six months (J. H. U. Applied Physics Laboratory, 1977) are more appropriate for annual load leveling. On a daily basis Central Vermont Public Service Corporation can consistently achieve load factors of over 90% by combining forecasting, TES scheduling, and a deferrable load of 70MWH. This corresponds to approximately 7,500 average all electric customers.

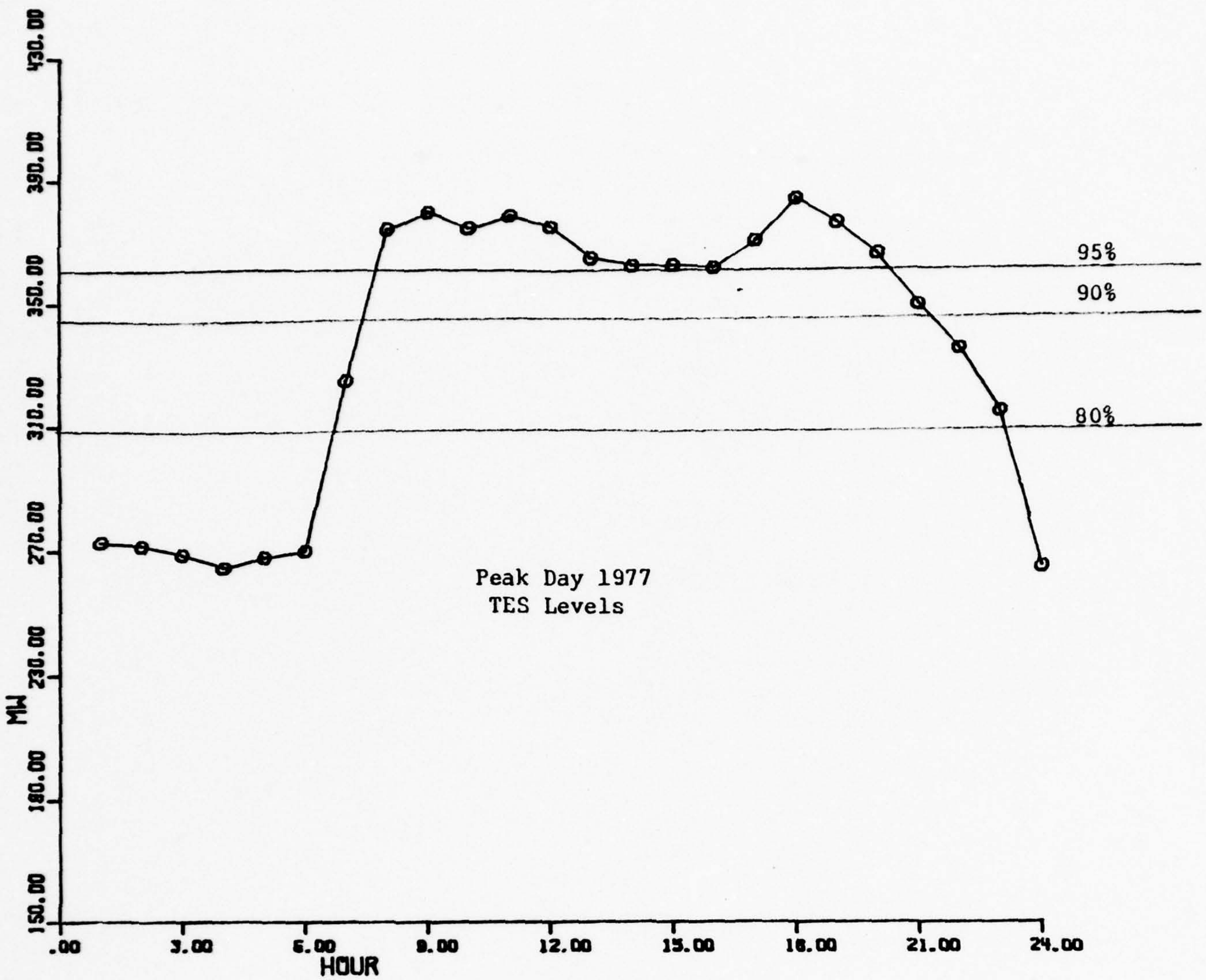


Fig. 14 TES Charging Levels

CHAPTER V

FURTHER STUDY

V. 1.0 Introduction

Potentially promising areas for further forecasting investigation are proposed along with possible improvements to the hybrid forecasting algorithm developed here.

V. 1.1 Recommendations for Further Study

No attempt has been made in this study to determine the optimum number of TES customers for a utility. There would seem to be a limit beyond which additional TES units would not be economically beneficial from the standpoint of daily load factor improvement. However, by controlling a significant percentage of winter loads the increased system security is certainly valuable to the utility, regardless of possible operating efficiency improvements. In fact a completely TES system is viable.

V. 1.2 Summer Peaking Affects

The assumed daily temperature profile for this study most closely matches summer days and, hence, accuracy is higher in that season. Conversely it would be valuable to study the accuracy of this forecasting method when applied to a summer peaking system.

V. 1.3 Winter Peaking Affects

Could the forecasting model be optimized for the heating season? This is the area of greatest potential improvement from the standpoint of load leveling and probably of the greatest benefit to most utilities.

V. 1.4 Alternate Applications of Forecast

Assuming a basic forecast is available then to what other uses could a small utility apply it? With the advent of smaller municipally owned utilities which control their own limited generating facilities, what accuracy forecast versus degree of complexity will be required for their efficient and secure operation?

Buying and selling blocks of power generating capacity between utilities is often done on contracts lasting only a few days to a month. As fossil energy costs continue to rise the selling of alternate capacity may increase. Can the algorithm be extended to provide a basis for these sales by forecasting surpluses?

V. 2.0 Recommended Model Improvements

Other weather variables such as wind speed and cloud cover which were not included in the current forecasting model are readily available in the existing data files generated in this study. Further study incorporating cloud and wind into the prediction algorithm would probably improve accuracy.

A multivariate time-series program is now available on the University computer system. Improved accuracies by including weather variables in the time-series formulation are probable and should be investigated.

CHAPTER VI

CONCLUSION

Two conclusions can be drawn from this study. First, that system loads such as those of Central Vermont Public Service Corporation can be simply forecast, using a first order linear model. Average yearly forecast errors are approximately 5%. The computation, data storage, and software maintenance requirements are minimal, so that a small utility can utilize the algorithm at the operating level without additional dedicated resources.

Secondly, operating economies which can be derived from a foreknowledge of system loads extend beyond mere scheduling of generating capacity, but includes expanded potential for system security through controlled load shedding using ripple control. Combining a forecast with the availability to defer loads (TES) and centralized control, immediately improves system load factors. A utility with these three capabilities will possess distinct operating advantages in the energy scarce future.

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APPENDIX 1

ORGANIZATION OF DATA

The standard annual calendar used to name data files is presented followed by a sample day's data.

Cloud cover is coded:

0....clear

2....partly cloudy

4....cloudy

6....rain

8....snow

The Number of Each Day of the Year

Day of Month	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Day of Month
1	1	32	60	91	121	152	182	213	244	274	305	335	1
2	2	33	61	92	122	153	183	214	245	275	306	336	2
3	3	34	62	93	123	154	184	215	246	276	307	337	3
4	4	35	63	94	124	155	185	216	247	277	308	338	4
5	5	36	64	95	125	156	186	217	248	278	309	339	5
6	6	37	65	96	126	157	187	218	249	279	310	340	6
7	7	38	66	97	127	158	188	219	250	280	311	341	7
8	8	39	67	98	128	159	189	220	251	281	312	342	8
9	9	40	68	99	129	160	190	221	252	282	313	343	9
10	10	41	69	100	130	161	191	222	253	283	314	344	10
11	11	42	70	101	131	162	192	223	254	284	315	345	11
12	12	43	71	102	132	163	193	224	255	285	316	346	12
13	13	44	72	103	133	164	194	225	256	286	317	347	13
14	14	45	73	104	134	165	195	226	257	287	318	348	14
15	15	46	74	105	135	166	196	227	258	288	319	349	15
16	16	47	75	106	136	167	197	228	259	289	320	350	16
17	17	48	76	107	137	168	198	229	260	290	321	351	17
18	18	49	77	108	138	169	199	230	261	291	322	352	18
19	19	50	78	109	139	170	200	231	262	292	323	353	19
20	20	51	79	110	140	171	201	232	263	293	324	354	20
21	21	52	80	111	141	172	202	233	264	294	325	355	21
22	22	53	81	112	142	173	203	234	265	295	326	356	22
23	23	54	82	113	143	174	204	235	266	296	327	357	23
24	24	55	83	114	144	175	205	236	267	297	328	358	24
25	25	56	84	115	145	176	206	237	268	298	329	359	25
26	26	57	85	116	146	177	207	238	269	299	330	360	26
27	27	58	86	117	147	178	208	239	270	300	331	361	27
28	28	59	87	118	148	179	209	240	271	301	332	362	28
29	29		88	119	149	180	210	241	272	302	333	363	29
30	30		89	120	150	181	211	242	273	303	334	364	30
31	31		90		151		212	243		304		365	31

For leap years the number of the day after February 28 is one greater than that given in the table.

NAME = 182-77

					Hr	MWH	Cloud Cover	Temp	Wind Speed
1.000	1	JUL	77	FRI	1	138.4	2	68	0
2.000	1	JUL	77	FRI	2	125.2	2	68	0
3.000	1	JUL	77	FRI	3	116.4	2	68	0
4.000	1	JUL	77	FRI	4	121.2	2	69	0
5.000	1	JUL	77	FRI	5	119.5	2	68	0
6.000	1	JUL	77	FRI	6	121.8	2	70	0
7.000	1	JUL	77	FRI	7	145.9	2	74	0
8.000	1	JUL	77	FRI	8	205.2	2	76	0
9.000	1	JUL	77	FRI	9	220.2	6	75	0
10.000	1	JUL	77	FRI	10	237.7	6	75	0
11.000	1	JUL	77	FRI	11	238.3	4	75	0
12.000	1	JUL	77	FRI	12	243.5	4	78	8
13.000	1	JUL	77	FRI	13	230.5	4	84	10
14.000	1	JUL	77	FRI	14	233.9	2	86	8
15.000	1	JUL	77	FRI	15	236.2	2	89	4
16.000	1	JUL	77	FRI	16	225.3	2	90	8
17.000	1	JUL	77	FRI	17	231.6	2	90	1
18.000	1	JUL	77	FRI	18	220.5	0	89	2
19.000	1	JUL	77	FRI	19	229.2	0	87	6
20.000	1	JUL	77	FRI	20	198.0	2	85	0
21.000	1	JUL	77	FRI	21	210.6	2	77	0
22.000	1	JUL	77	FRI	22	214.4	2	72	0
23.000	1	JUL	77	FRI	23	192.7	2	68	0
24.000	1	JUL	77	FRI	24	167.9	2	67	0

Sample Data File

APPENDIX 2

COMPUTER PROGRAMS

The programs listed are written in Fortran IV for the University of Vermont Sigma 6 operating system. The library routines utilized were current on the system as of the date of this report.

Pages 74 to 76 contain a listing of a general mainline program which interfaces the system operator with a particular forecasting program. This routine also selects two prior similar days on which a forecast is based.

Pages 77 to 80 are a subroutine which forecasts the hourly system load twenty-four hours in advance using gains fixed less than 1.5.

Pages 81 to 84 are another subroutine which forecasts the system load for February 1976, but which employs manually entered hourly gain coefficients produced off-line with a statistical routine.

```
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C
C
C      PROGRAM TO INTERFACE DISPATCHERS AND FORECASTING ROUTINES
C
C
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C
C     PROGRAM MUST BE USED WITH A PREDICTION SUBROUTINE
C
C      FORT OPTIONS MUST BE BOTH BC AND S
C
C      LINK WITH :LIB.EDS
C
       DIMENSION MWARRAY(24,1),TEMPARRAY(24,1),JULIANDATE(3),D(10),A(12)
       DIMENSION FILE(3),DIGET(3),DATE(2),DATE3(2),DATE2(2),DATE1(2)
       INTEGER CHANGE1,HOLIDAY,CHANGE2,YEARCHANGE
        IMPLICIT INTEGER (A-H)
       COMMON YEARCHANGE,CHANGE1,CHANGE2
        CALL LIBINIT
C
C      READ DATE TO BE FORECAST FROM CRT
       WRITE(108,10)
10     FORMAT('WHAT IS THE JULIAN DATE TO BE FORECAST ?? I.E.100-76')
C
           READ (108,20) DATE3(I),I=1,2
20     FORMAT(2A4)
       WRITE (108,30)
C      READ DAY OF WEEK TO BE FORECAST FROM CRT
C
30     FORMAT('WHAT DAY OF WEEK IS TO BE FORECAST??')
C
       READ (108,40)DAYOFWK
40     FORMAT (A2)
C
C   CHECK TO SEE IF FORECAST IS FOR A SPECIAL HOLIDAY
       WRITE (108,50)
50     FORMAT ('IS THE DAY A SPECIAL HOLIDAY OTHER THAN SAT OR SUN?')
       READ (108,60)HOLIDAY
60     FORMAT (A4)
C
C    SET ERROR FLAG
       CHANGE1=2
C
C    SET BRANCH CHANGES FOR APPROPRIATE SIMILIAR DAY
C
       IF (DAYOFWK.EQ.2HSU)          CHANGE1=-7;CHANGE2=-1
       IF (DAYOFWK.EQ.2HSA)           CHANGE1=-7;CHANGE2=+1
```

```
      IF (DAYOFWK.EQ.2HTU)              CHANGE1=-4;CHANGE2=-1
C
      IF (DAYOFWK.EQ.2HMO)CHANGE1=-7;CHANGE2=+4
C
      IF ((DAYOFWK .EQ. 2HWE) .OR. (DAYOFWK .EQ. 2HTH) .OR.
     #(DAYOFWK .EQ. 2HFR)) CHANGE1=-1;CHANGE2=-1
C
C
       YEARCHANGE=0
       IF(HOLIDAY .EQ. 1HY)YEARCHANGE=-1;CHANGE1=0;CHANGE2=-1
C
C  STOP IF ERROR FLAG HAS NOT BEEN CHANGED FROM 2
C
      IF (CHANGE1 .EQ. 2) WRITE (108,70);GO TO 101
70    FORMAT ('INPUT ERROR IN DATE DAY OR HOLIDAY. JOB STOPPED!')
C
C  COMPUTE NAME OF PRIOR SIMILIAR DAY FILE
C
       DATE1(1)=DATE3(1)
       DATE1(2)=DATE3(2)
      CALL BASEDATE  (DATE3,CHANGE1,YEARCHANGE)
C
C   COMPUT NAME OF EARLIEST SIMILIAR DAY FILE FOR GAINS
C
        DATE2(1)=DATE3(1)
        DATE2(2)=DATE3(2)
       CALL BASEDATE (DATE3,CHANGE2,YEARCHANGE)
C   OUTPUT TO CRT NAMES OF 3 FILES USED (OPTIONAL)
C
       WRITE (108,9998) DATE1,DATE2,DATE3
C
9998    FORMAT (X,'DATE1=',X,2A4,4X,'DATE2=',X,2A4,4X,'DATE3=',2A4)
       CALL PREDICT (DATE1,DATE2,DATE3)
101   CALL EXIT
      STOP 'NORMAL ENDING'
      END
C
C
C         SUBROUTINE TO COMPUTE EARLIER DAY FILE NAME
C
      SUBROUTINE BASEDATE (DATE,CHANGE,YEARCHANGE)
      INTEGER DATE(2),TEMP,CHANGE,YEARCHANGE
C    CONVERT NAME TO NUMERIC
C
*
S     LI,1        1
S     LW,3        *DATE,1
S     LI,2        X'F0'
S     SLD,2       -8
S     STW,3       *DATE,1
```

```
      DECODE(4,9,DATE(1))DATE(1)
      DATE(1)=DATE(1)+CHANGE
C
C    CHECK TO SEE IF YEAR COMPUTED IS CORRECT
C
              IF (DATE(1) .LE. 0) DATE(1)=365+CHANGE;YEARCHANGE=-1
              IF (DATE(1) .GE. 367) STOP 'JULIAN DATE ERROR'
C
      TEMP=DATE(1)
C   MAKE SURE PROPER NUMBER OF ZERO'S ARE IN NAME
C
       IF(DATE(1).LE.9)ENCODE(4,997,DATE(1))TEMP;GO TO 102
       IF(DATE(1).LE.99)ENCODE(4,998,DATE(1))TEMP
C
C     CONVERT BACK TO ALPHABETIC NAME
C
102               IF (DATE(1) .GE. 100)ENCODE(4,999,DATE(1))TEMP
S     LI,1         2
S     LW,3         *DATE,1
S     LI,2         X'FOFO'
S     SLD,2        -16
S     STW,3        *DATE,1
      DECODE(4,9,DATE(2))DATE(2)
      TEMP=DATE(2)
      TEMP=TEMP+YEARCHANGE
      ENCODE(4,90,DATE(2))TEMP
9     FORMAT(I4)
90    FORMAT(I2)
99    FORMAT(X,A4)
999   FORMAT(I3,'-')
997   FORMAT ('00',I1,'-')
998   FORMAT('0',I2,'-')
9999  FORMAT(X,2A4)
      RETURN
      END
```

```
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C
C
C             LINEAR PREDICTION ROUTINE
C         GAINS COMPUTED  FROM PREVIOUS HOUR OF PREVIOUS TWO DAYS
C
C
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C   CALLING PROGRAM PASSES THREE FILE NAMES TO THIS SUBROUTINE
C    ALL FILES NAMED MUST BE ON DISK OR THE OPENF CALLS CHANGED
C    TO ACCESS TAPES.
C   OUTPUT CONSISTS OF TWO FILES 'ACTUAL' AND 'PREDICTED' LOADS
C    IN ADDITION TO LP & CRT TABULATIONS.
C
C     DCB#3 IS THE FID TO BE PREDICTED
C     DCB#2 IS THE FID FOR PRIOR SIMILIAR DAY
C     DCB#2 IS THE FID FOR EARLIEST DAY USED IN GAIN PREDICTION
C
C     SUBROUTINE MUST BE USED WITH PROGRAM 'MAINLINE' AND
C      LINKED WITH  :LIB.EDS
C     FORT OPTIONS MUST BE BC,S
C
C
      SUBROUTINE  PREDICT (DATE1,DATE2,DATE3)
       DIMENSION DAY(24,2),FUTURE(24,2),PREDICTION(24),DIFFERENCE(24),
     *  PERCENT(24),GAIN(24),DAYONE(24,2),DENOMATOR(24)
      REAL PMFACT
        INTEGER H1,H2,H3
            CALL OPENF (1,DATE3,2,0,0,1,1,7,0,0,0)
             CALL OPENF (2,DATE2,2,0,0,1,1,7,0,0,0)
            CALL OPENF (3,DATE1,2,0,0,1,1,7,0,0,0)
C
C   READ MW & TEMPERATURE BY HOUR INTO 3 ARRAYS FOR 3 DAYS USED
C
       DO 40 I=1,24
         READ (1,30) (DAYONE(I,J),J=1,2)
       READ (2,30)( DAY(I,J),J=1,2)
          READ (3,30) (FUTURE(I,J),J=1,2)
30     FORMAT(X,T35,F5.1,T50,G)
40     CONTINUE
C
C   READ AND OUTPUT DAY AND DAY INFO ON DAY TO BE PREDICTED
C
      REWIND(3)
      READ (3,31) PTE31,PTE32,PTE33,PY3
31    FORMAT (3A4,T20,A4)
      WRITE (6,32) PY3,PTE31,PTE32,PTE33
      WRITE (108,32) PY3,PTE31,PTE32,PTE33
```

```
32     FORMAT (1H1,'PREDICTION FOR',2X,A4,X,3A4,2X,'****',/)
C
C    READ AND OUTPUT DATE & DAY INFO ON PRIOR SIMILIAR DAY
C
       REWIND(2)
       READ (2,31) PTE21,PTE22,PTE23,PY2
       WRITE (6,33) PY2,PTE21,PTE22,PTE23
       WRITE (108,33) PY2,PTE21,PTE22,PTE23
33     FORMAT(X,'PREDICTION USES',2X,A4,X,3A4,X,'AS BASE DAY.',/)
C
C     READ AND OUTPUT DATE & DAY INFO ON EARLIEST DAY FOR GAIN
C
        REWIND(1)
        READ (1,31) PTE11,PTE12,PTE13,PY1
        WRITE (6,34) PY1,PTE11,PTE12,PTE13
        WRITE (108,34)PY1,PTE11,PTE12,PTE13
34      FORMAT (X,'GAIN BASED ON',2X,A4,X,3A4,/)
C
C      CHECK FILES FOR HOLIDAY
C
        REWIND (1)
        READ (1,35) H1
        REWIND (2)
        READ (2,35) H2
        REWIND (3)
        READ (3,35) H3
35     FORMAT (X,T12,A4)
       IF ((H1.EQ.1HH).OR.(H2.EQ.1HH).OR.(H3.EQ.1HH))WRITE (6,37);
      #WRITE (108,37)
37     FORMAT (X,'****** WARNING ONE OF THE DAYS USED IN THIS FORECAST
      #WAS A HOLIDAY ******',/)
C
C       PRINT INFO ON ANY GAIN RESTRICTION FOR REF.
C
           WRITE (6,38)
38         FORMAT(X,'GAIN IS FIXED LESS THAN 1.5.  ',/)
C
C     FIND MIN. & MAX. TEMPERATURES FROM PRIOR SIMILIAR DAY
C
        TEMPMAX=-20.0
        TEMPMIN=400.0
C
        DO 60 I=1,24
C
          IF(DAY(I,2) .GT. TEMPMAX) TEMPMAX=DAY(I,2)
          IF(DAY(I,2) .LT. TEMPMIN) TEMPMIN=DAY(I,2)
C
60        CONTINUE
C
C   INPUT FROM CRT FORECASTED MIN. & MAX. TEMPERATURES
```

```
C
            WRITE (108,98)
98           FORMAT (X,'WHAT IS THE MIN. FORECASTED TEMPERATURE?')
             READ (108,97) FUTUREMIN
97           FORMAT(G)
C
              WRITE (108,96)
96            FORMAT(X,'WHAT IS THE MAX. FORECASTED TEMPERATURE?')
               READ (108,97) FUTUREMAX
C
C    COMPUTE HOURLY GAINS  G(I)
C
         DO 85 I=1,24
      DENOMATOR(I)=DAY(I,2)-DAYONE(I,2)
      IF (DENOMATOR(I) .EQ. 0.0) DENOMATOR(I)=10.0
C
C   RESTRICT GAINS LESS THAN 1.5
C
      GAIN(I)=ABS((DAY(I,1)-DAYONE(I,1))/DENOMATOR(I))
       IF (GAIN(I)   .GE. 1.5)  GAIN(I)=1.0
85      CONTINUE
C
C     MORNING PREDICTION
C
      SCALEAM=(TEMPMIN-FUTUREMIN)
C
C     PREVENT DENOMINATOR FROM = 0
C
      IF (SCALEAM .EQ. 0.0) SCALEAM=1.0
          DO 80 I=1,12
          PREDICTION(I)=(DAY(I,1))+((GAIN(I))*(SCALEAM))
80        CONTINUE
C
C    AFTERNOON LOAD PREDICTIONS
C
         CALL OPENF(4,'ACTUAL    ',4,0,0,0,0,7)
          CALL OPENF (5,'PREDICTED   ',4,0,0,0,0,7)
      SCALEPM=(TEMPMAX-FUTUREMAX)
      IF (SCALEPM .EQ. 0.0) SCALEPM=1.0
C
              DO 100 I=13,24
              PREDICTION(I)=(DAY(I,1))+((GAIN(I))*(SCALEPM))
100           CONTINUE
            TOTAL=0.0
C
C     OUTPUT RESULT HEADINGS TO LP & CRT
C
        WRITE (108,95)
         WRITE (6,95)
95    FORMAT(X,'PREDICTION',T16,'ACTUAL MW',T30,'DIFFERENCE',T53,'%',
```

```
     *T63,'GAIN',/)
          TOTALMWPRE=0.0
          TOTALMWFUT=0.0
           DO 110 I=1,24
           DIFFERENCE(I)=(PREDICTION(I)-FUTURE(I,1))
           PERCENT(I)=(ABS(DIFFERENCE(I))/FUTURE(I,1))*100
       WRITE(108,99)PREDICTION(I),FUTURE(I,1),DIFFERENCE(I),PERCENT(I)
     *,GAIN(I)
       WRITE(6,99)PREDICTION(I),FUTURE(I,1),DIFFERENCE(I),PERCENT(I)
     *,GAIN(I)
99          FORMAT(X,F8.4,T16,F8.4,T30,F8.4,T50,F6.2,T60,F8.4)
                TOTAL=TOTAL+PERCENT(I)
                      TOTALMWPRE=PREDICTION(I)+TOTALMWPRE
                      TOTALMWFUT=TOTALMWFUT+FUTURE(I,1)
           WRITE (4,90)I,FUTURE(I,1)
90         FORMAT (X,I,F6.2)
           WRITE (5,90) I,PREDICTION(I)
110               CONTINUE
           CALL CLOSEF(4,2)
           CALL CLOSEF(5,2)
C
C    COMPUTE & OUTPUT TOTAL DAILY ERROR
C
                      DAYPERCENT=(TOTALMWFUT/TOTALMWPRE)*100
                 AVGPERCENT= TOTAL/24.0
               WRITE (108,999) AVGPERCENT,DAYPERCENT
               WRITE (6,999) AVGPERCENT,DAYPERCENT
999            FORMAT (/,'AVG. OF HOURLY PERCENT ERRORS=',2X,F6.2,//,
     #  'PERCENT ERROR FOR TOTAL DAILY POWER=',2X,F6.2)
C
C      CLOSE ALL FILES
C
      CALL CLOSEF (1,2)
      CALL CLOSEF (2,2)
      CALL CLOSEF (3,2)
      RETURN
      END
```

```
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C
C
C           LINEAR PREDICTION ROUTINE
C       GAINS COMPUTED BY SPSS SLOPE FOR 30 DAY PERIOD
C                 **** FEB 76 ****
C
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C       CALLING PROGRAM PASSES THREE FILE NAMES TO SUBROUTINE
C        ALL FILES NAMED MUST BE AVAILABLE ON DISK OR OPENF
C        ROUTINES CHANGED TO ACCESS TAPES.
C       OUTPUT CONSISTS OF LP & CRT TABLES.  TWO FILES ARE ALSO
C        CREATED CONSISTING OF 'ACTUAL' AND 'PREDICTED' LOADS.
C       DCB#3 IS THE FID TO BE PREDICTED
C        DCB#2 IS THE FID FOR THE PRIOR SIMILIAR DAY
C        DCB#1 IS FID FOR EARLIEST DAY USED IN GAIN COMPUTATION
C
C       SUBROUTINE MUST BE USED WITH PROGRAM 'MAINLINE' AND
C        LINKED WITH :LIB.EDS
C       FORT OPTIONS MUST BE DECLAIRED BOTH BC AND S.
C
C
      SUBROUTINE  PREDICT (DATE1,DATE2,DATE3)
       DIMENSION DAY(24,2),FUTURE(24,2),PREDICTION(24),DIFFERENCE(24),
     *  PERCENT(24),GAIN(24),DAYONE(24,2),DENOMATOR(24)
      REAL PMFACT
        INTEGER H1,H2,H3
            CALL OPENF (1,DATE3,2,0,0,1,1,7,0,0,0)
             CALL OPENF (2,DATE2,2,0,0,1,1,7,0,0,0)
            CALL OPENF (3,DATE1,2,0,0,1,1,7,0,0,0)
C
C    READ MW & TEMP BY HOUR INTO 3 ARRAYS FOR 3 DAYS USED
       DO 40 I=1,24
C
         READ (1,30) (DAYONE(I,J),J=1,2)
       READ (2,30)( DAY(I,J),J=1,2)
          READ (3,30) (FUTURE(I,J),J=1,2)
30     FORMAT(X,T35,F5.1,T50,G)
40     CONTINUE
C
C    READ AND OUTPUT DATE AND DAY INFO ON DAY TO BE PREDICTED
      REWIND(3)
      READ (3,31) PTE31,PTE32,PTE33,PY3
31    FORMAT (3A4,T20,A4)
      WRITE (6,32) PY3,PTE31,PTE32,PTE33
      WRITE (108,32) PY3,PTE31,PTE32,PTE33
32    FORMAT (1H1,'PREDICTION FOR',2X,A4,X,3A4,2X,'****',/)
C
```

```
C     READ AND OUTPUT DATE & DAY INFO ON PRIOR SIMILIAR DAY
       REWIND(2)
       READ (2,31) PTE21,PTE22,PTE23,PY2
       WRITE (6,33) PY2,PTE21,PTE22,PTE23
       WRITE (108,33) PY2,PTE21,PTE22,PTE23
33     FORMAT(X,'PREDICTION USES',2X,A4,X,3A4,X,'AS BASE DAY.',/)
C
C     READ AND OUTPUT DATE & DAY INFO ON EARLIEST DAY FOR GAIN
        REWIND(1)
        READ (1,31) PTE11,PTE12,PTE13,PY1
        WRITE (6,34) PY1,PTE11,PTE12,PTE13
        WRITE (108,34)PY1,PTE11,PTE12,PTE13
34      FORMAT (X,'GAIN BASED ON',2X,A4,X,3A4,/)
C
C     CHECK EACH DAY FOR HOLIDAY
        REWIND (1)
        READ (1,35) H1
        REWIND (2)
        READ (2,35) H2
        REWIND (3)
        READ (3,35) H3
35     FORMAT (X,T12,A4)
       IF ((H1.EQ.1HH).OR.(H2.EQ.1HH).OR.(H3.EQ.1HH))WRITE (6,37);
      #WRITE (108,37)
37     FORMAT (X,'****** WARNING ONE OF THE DAYS USED IN THIS FORECAST
      #WAS A HOLIDAY ******',/)
C
            WRITE (6,38)
38          FORMAT(X,'GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION',/)
C
C      FIND MIN. & MAX. TEMPERATURE FROM PRIOR SIMILIAR DAY
        TEMPMAX=-20.0
        TEMPMIN=400.0
C
        DO 60 I=1,24
C
          IF(DAY(I,2) .GT. TEMPMAX) TEMPMAX=DAY(I,2)
          IF(DAY(I,2) .LT. TEMPMIN) TEMPMIN=DAY(I,2)
C
60        CONTINUE
C
C      INPUT FROM CRT FORECASTED MIN. & MAX. TEMPERATURES
               WRITE (108,98)
98              FORMAT (X,'WHAT IS THE MIN. FORECASTED TEMPERATURE?')
                READ (108,97) FUTUREMIN
97              FORMAT(G)
C
                 WRITE (108,96)
96               FORMAT(X,'WHAT IS THE MAX. FORECASTED TEMPERATURE?')
                  READ (108,97) FUTUREMAX
```

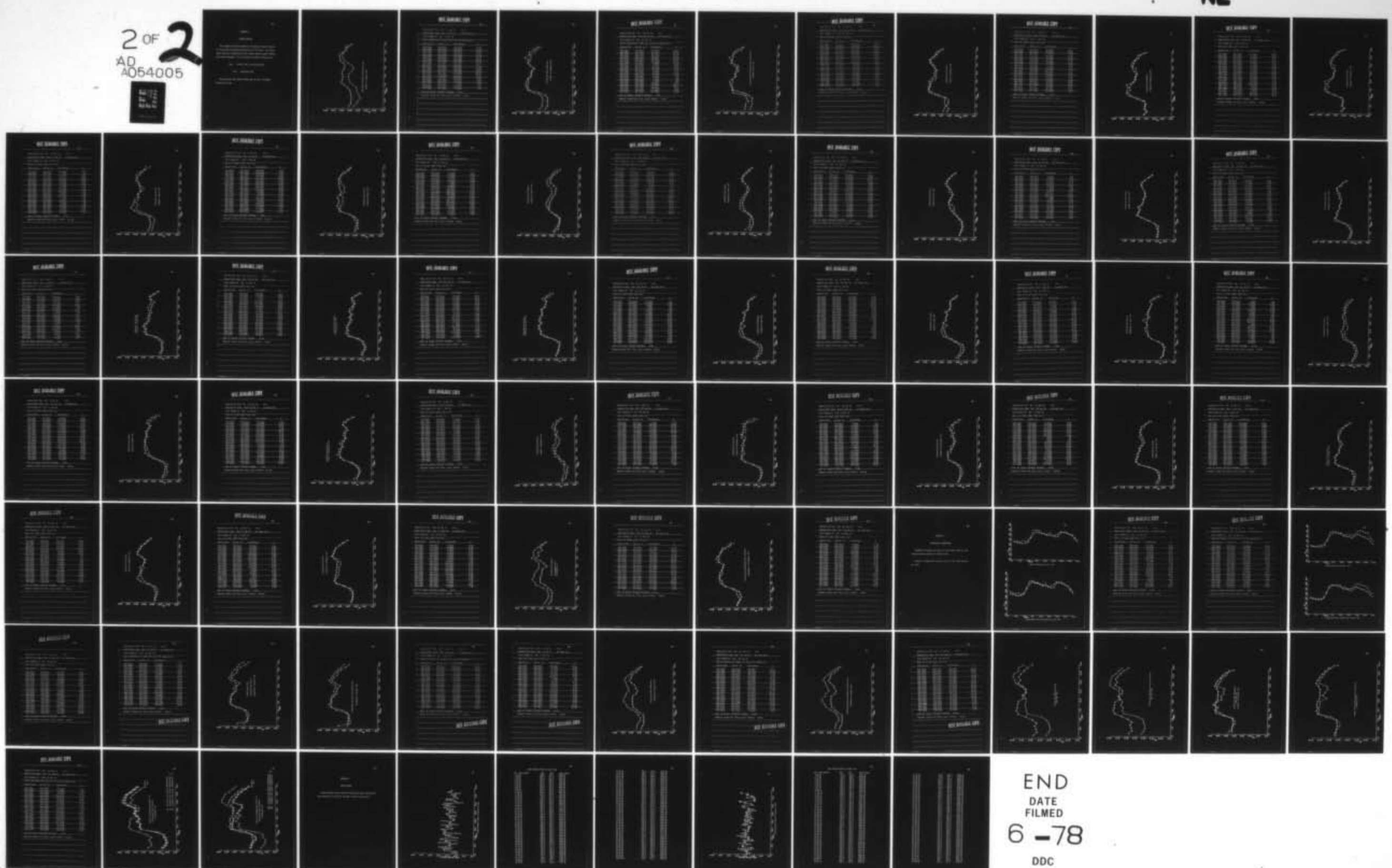
```
C     SPSS GAINS LISTED HERE FOR MONTH OF PREDICTION (FEB 76)
         GAIN(1) =1.5
         GAIN(2) =.989
         GAIN(3) =1.19
         GAIN(4) =.56
         GAIN(5) =.624
         GAIN(6) =.474
         GAIN(7) =1.18
         GAIN(8) =.21
         GAIN(9) =.62
         GAIN(10)=.24
         GAIN(11)=1.6
         GAIN(12)=1.08
         GAIN(13)=1.16
         GAIN(14)=.752
         GAIN(15)=.389
         GAIN(16)=1.07
         GAIN(17)=.81
         GAIN(18)=1.02
         GAIN(19)=.84
         GAIN(20)=.52
         GAIN(21)=1.03
         GAIN(22)=.196
         GAIN(23)=.995
         GAIN(24)=1.12
C     MORNING LOAD PREDICTIONS
C
      SCALEAM=(TEMPMIN-FUTUREMIN)
      IF (SCALEAM .EQ. 0.0) SCALEAM=1.0
          DO 80 I=1,12
          PREDICTION(I)=(DAY(I,1))+((GAIN(I))*(SCALEAM))
80        CONTINUE
         CALL OPENF(4,'ACTUAL  ',4,0,0,0,0,7)
          CALL OPENF (5,'PREDICTED  ',4,0,0,0,0,7)
C     AFTERNOON LOAD PREDICTIONS
C
      SCALEPM=(TEMPMAX-FUTUREMAX)
      IF (SCALEPM .EQ. 0.0) SCALEPM=1.0
C
              DO 100 I=13,24
              PREDICTION(I)=(DAY(I,1))+((GAIN(I))*(SCALEPM))
100           CONTINUE
            TOTAL=0.0
C
C     OUTPUT RESULT HEADINGS TO LP & CRT
         WRITE (108,95)
          WRITE (6,95)
95    FORMAT(X,'PREDICTION',T16,'ACTUAL MW',T30,'DIFFERENCE',T53,'%',
     *T63,'GAIN',/)
C
```

```
C     COMPUTE % ERROR FOR EACH HOUR
C
           TOTALMWPRE=0.0
           TOTALMWFUT=0.0
            DO 110 I=1,24
            DIFFERENCE(I)=(PREDICTION(I)-FUTURE(I,1))
            PERCENT(I)=(ABS(DIFFERENCE(I))/FUTURE(I,1))*100
C     OUTPUT RESULTS TO LP,CRT AND OUTPUT FILES
C
        WRITE(108,99)PREDICTION(I),FUTURE(I,1),DIFFERENCE(I),PERCENT(I)
     *,GAIN(I)
        WRITE(6,99)PREDICTION(I),FUTURE(I,1),DIFFERENCE(I),PERCENT(I)
     *,GAIN(I)
99           FORMAT(X,F8.4,T16,F8.4,T30,F8.4,T50,F6.2,T60,F8.4)
                TOTAL=TOTAL+PERCENT(I)
                      TOTALMWPRE=PREDICTION(I)+TOTALMWPRE
                      TOTALMWFUT=TOTALMWFUT+FUTURE(I,1)
            WRITE (4,90)I,FUTURE(I,1)
90          FORMAT (X,I,F6.2)
            WRITE (5,90) I,PREDICTION(I)
110                CONTINUE
            CALL CLOSEF(4,2)
            CALL CLOSEF(5,2)
C
C      COMPUTE AND OUTPUT TOTAL DAILY ERRORS
                      DAYPERCENT=(TOTALMWFUT/TOTALMWPRE)*100
                AVGPERCENT= TOTAL/24.0
               WRITE (108,999) AVGPERCENT,DAYPERCENT
               WRITE (6,999) AVGPERCENT,DAYPERCENT
999            FORMAT (/,'AVG. OF HOURLY PERCENT ERRORS=',2X,F6.2,//,
     #  'PERCENT ERROR FOR TOTAL DAILY POWER=',2X,F6.2)
C
C       CLOSE ALL FILES
       CALL CLOSEF (1,2)
       CALL CLOSEF (2,2)
       CALL CLOSEF (3,2)
       RETURN
       END
```

AD-A054 005 VERMONT UNIV BURLINGTON DEPT OF ELECTRICAL ENGINEERING F/G 20/3
A METHOD FOR UTILITY LOAD MANAGEMENT USING SHORT TERM LOAD FORE--ETC(U)
MAY 78 R B OTTESEN

UNCLASSIFIED NL

2 OF 2
AD
A054005



END
DATE
FILMED
6 -78
DDC

APPENDIX 3

SAMPLE RESULTS

This appendix contains graphical follow

of thirty load forecasting simulations on l

dates used were selected by an APL random n

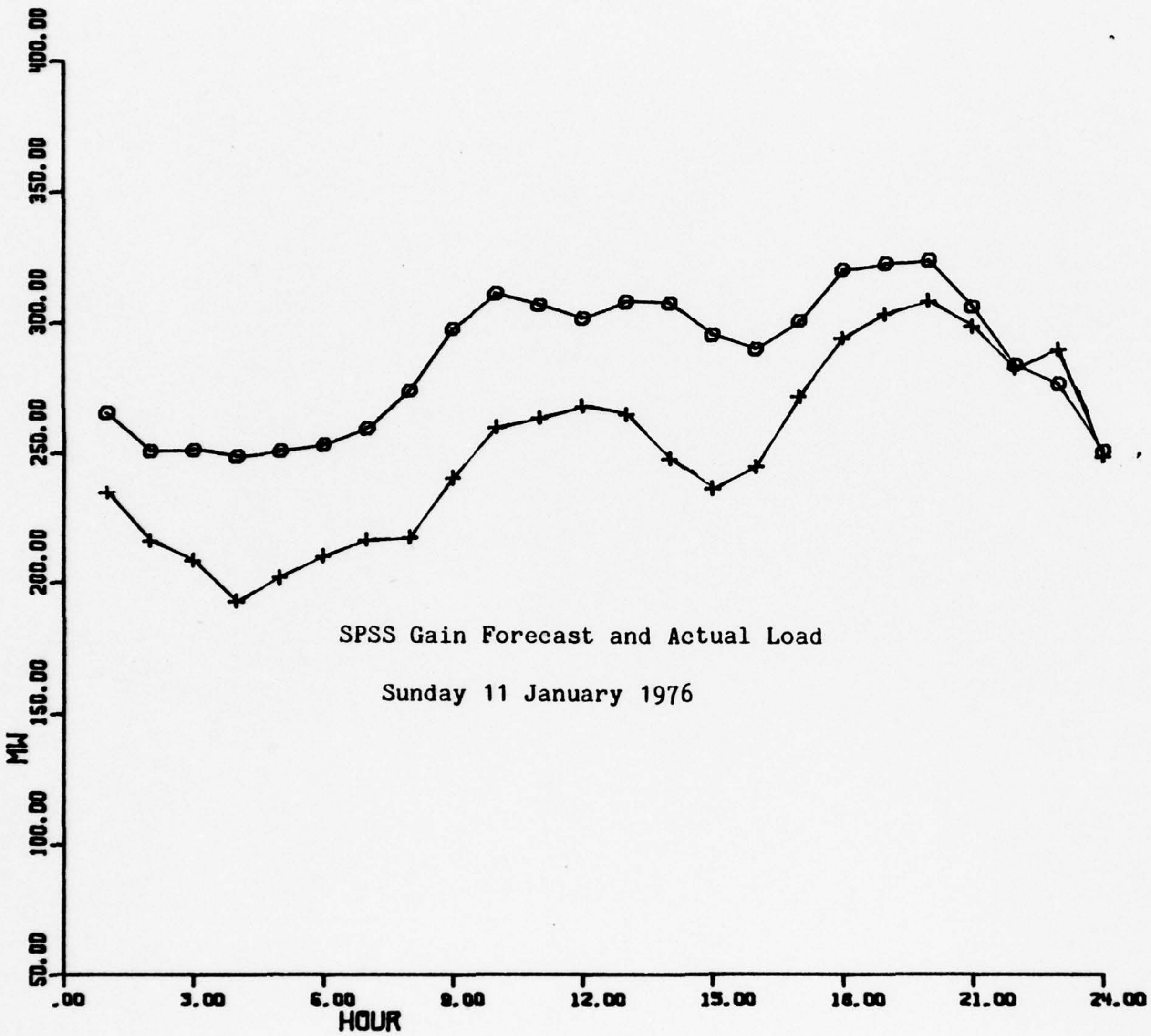
and include weekends. For all graphs the s

—o— Actual load on forec

—x— Predicted load

The mean error for these 30 days was 5.

deviation of 2.68.


SPSS Gain Forecast and Actual Load
Sunday 11 January 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR SUN 11 JAN 76 ****

PREDICTION USES SUN 4 JAN 76 AS BASE DAY.

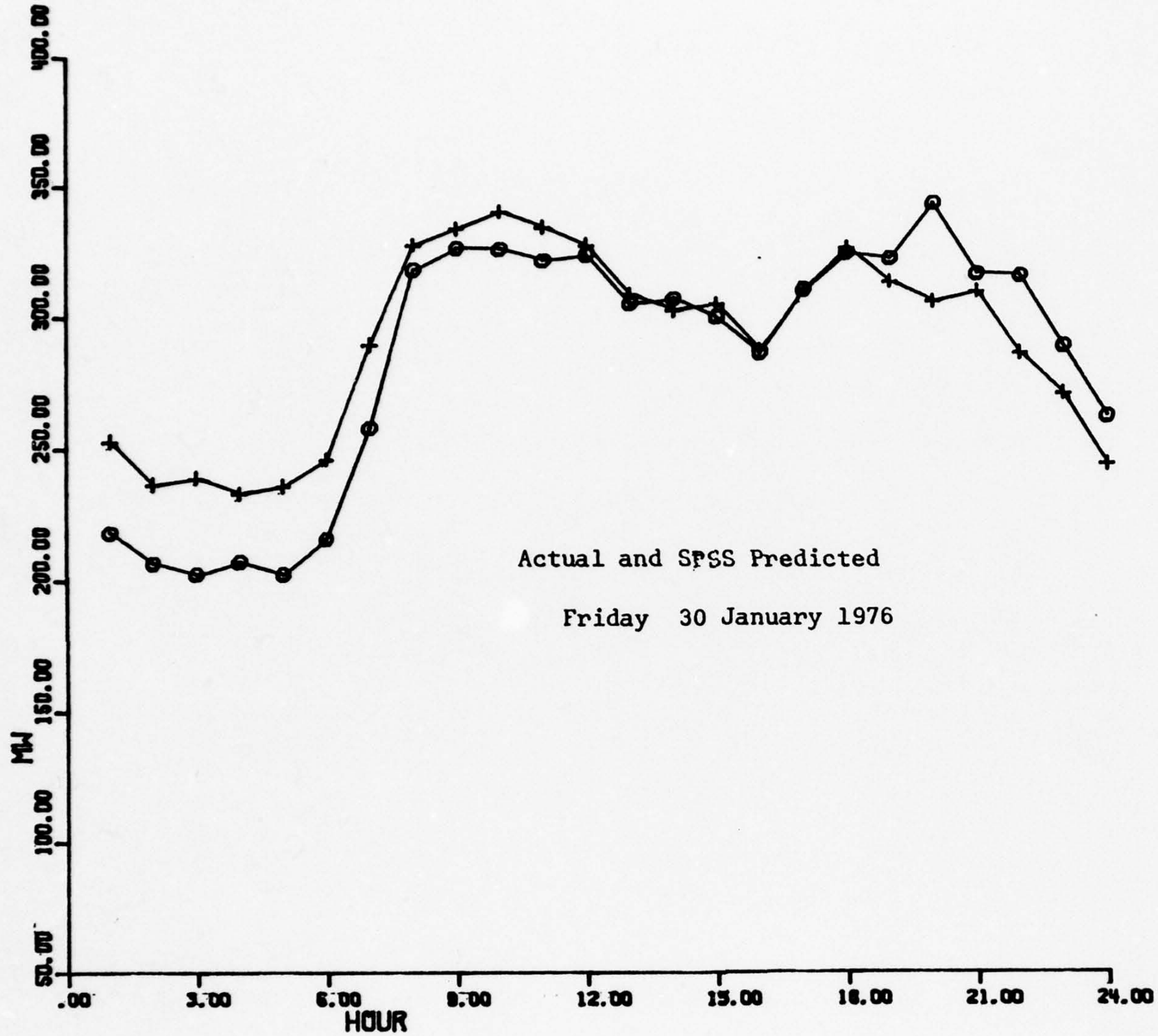
GAIN BASED ON SAT 3 JAN 76

GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

PREDICTION	ACTUAL MW	DIFFERENCE	%
234.5000	265.1001	-30.6001	11.54
216.0000	250.3000	-34.3000	13.70
208.4000	250.9000	-42.5000	16.94
192.8000	248.4000	-55.6000	22.38
201.7000	250.5000	-48.8000	19.48
210.1000	252.8000	-42.7000	16.89
216.5000	259.2000	-42.7000	16.47
217.5000	273.5000	-56.0000	20.48
240.2000	297.2000	-57.0000	19.18
259.7000	310.7000	-51.0000	16.41
263.2998	306.2000	-42.9001	14.01
267.7000	301.1001	-33.4001	11.09
264.4399	307.3999	-42.9600	13.98
247.5400	307.0000	-59.4600	19.37
235.5720	294.5000	-58.9280	20.01
244.1520	289.1001	-44.9481	15.55
271.1199	299.8999	-28.7800	9.60
293.5198	319.3999	-25.8801	8.10
302.8398	321.7000	-18.8601	5.86
307.7598	322.8999	-15.1401	4.69
297.8398	305.3000	-7.4602	2.44
282.0000	283.0000	-1.0000	.35
289.0400	275.8000	13.2400	4.80
247.9800	249.9000	-1.9200	.77

AVG. OF HOURLY PERCENT ERRORS= 12.67

PERCENT ERROR FOR TOTAL DAILY POWER= 113.80


Actual and SPSS Predicted
Friday 30 January 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR FRI 30 JAN 76 ****

PREDICTION USES THUR 29 JAN 76 AS BASE DAY.

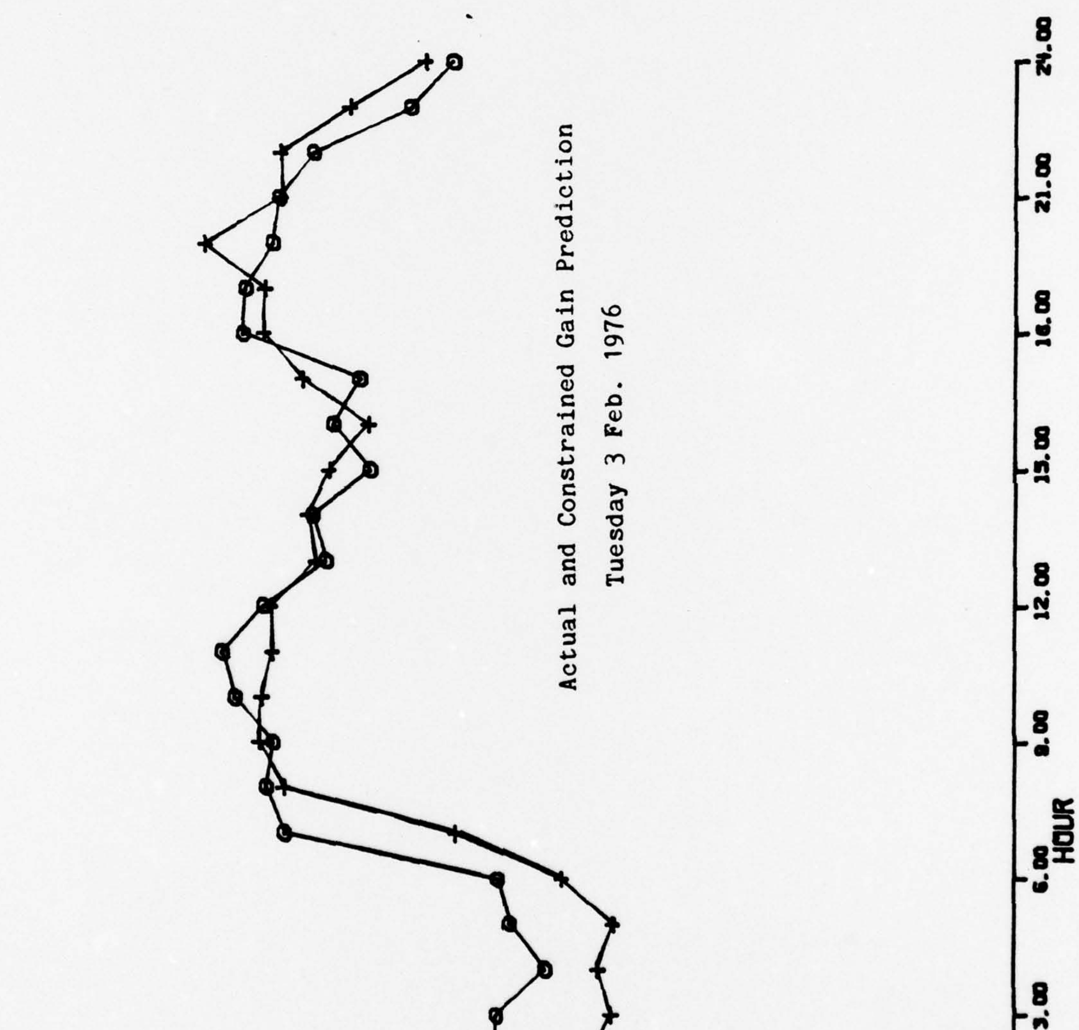
GAIN BASED ON WED 28 JAN 76

GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

PREDICTION	ACTUAL MW	DIFFERENCE	%
252.6300	217.9000	34.7300	15.94
236.3000	206.2000	30.1000	14.60
238.7300	202.1000	36.6300	18.12
232.8200	206.7000	26.1200	12.64
235.5700	202.0000	33.5700	16.62
245.7200	215.5000	30.2200	14.02
289.3000	257.6001	31.7000	12.31
327.1899	317.6001	9.5898	3.02
333.4500	325.7000	7.7500	2.38
339.9600	325.5000	14.4600	4.44
333.8899	321.1001	12.7898	3.98
326.9500	323.2000	3.7500	1.16
308.1299	304.6001	3.5298	1.16
302.0798	306.5000	-4.4202	1.44
304.2190	299.0000	5.2190	1.75
286.9038	285.3999	1.5039	.53
309.7400	309.5000	.2400	.08
325.3899	323.3999	1.9900	.62
312.5798	321.3999	-8.8201	2.74
305.1697	342.3999	-37.2302	10.87
308.8799	315.5000	-6.6201	2.10
285.3999	314.7000	-29.3000	9.31
270.4800	288.2000	-17.7200	6.15
243.5100	261.5000	-17.9900	6.88

AVG. OF HOURLY PERCENT ERRORS= 6.79

PERCENT ERROR FOR TOTAL DAILY POWER= 97.67



Actual and Constrained Gain Prediction

Tuesday 3 Feb. 1976

BEST AVAILABLE COPY

PREDICTIØN FØR TUE 3 FEB 76 ****

PREDICTIØN USES FRI 30 JAN 76 AS BASE DAY.

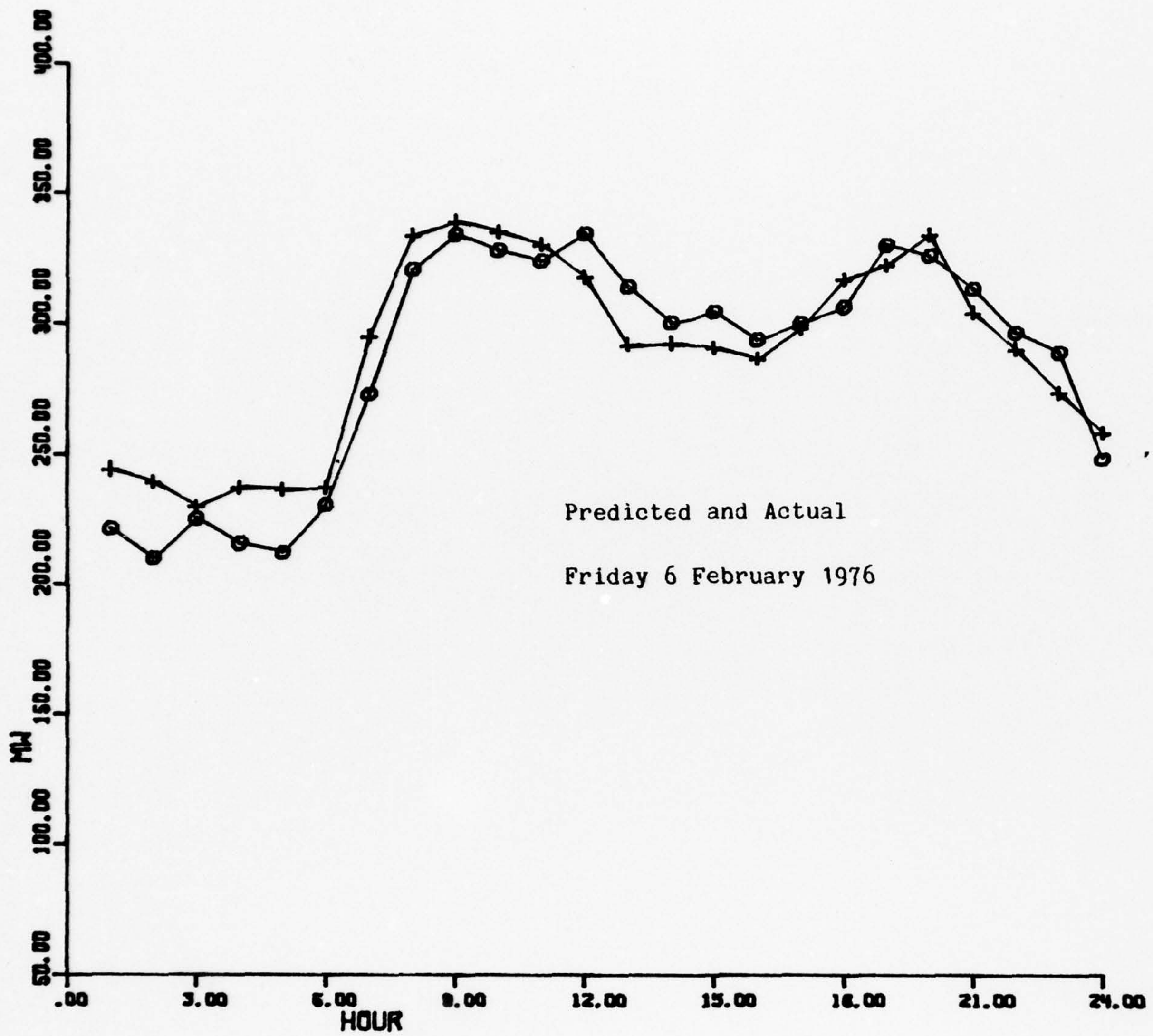
GAIN BASED ØN THUR 29 JAN 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL KW	DIFFERENCE	%
211.9000	242.1000	-30.2000	12.47
204.7000	239.5000	-34.8000	14.53
197.1000	238.9000	-41.8000	17.50
201.7000	220.8000	-19.1000	8.65
196.3750	234.1000	-37.7250	16.11
215.2500	238.4000	-23.1500	9.71
254.1557	316.0000	-61.8443	19.57
316.3501	322.5000	-6.1499	1.91
325.2000	319.8999	5.3000	1.66
324.2000	333.8000	-9.6001	2.88
320.5117	338.5000	-17.9883	5.31
320.8315	323.6001	-2.7686	.86
304.7000	300.8000	3.8999	1.30
307.7000	305.7000	2.0000	.65
299.7649	284.6001	15.1648	5.33
285.5569	298.1001	-12.5432	4.21
309.7607	288.5000	21.2607	7.37
323.8433	331.1001	-7.2568	2.19
323.2373	330.1001	-6.8628	2.08
345.3999	320.5000	24.8999	7.77
317.2654	317.8000	-.5347	.17
317.7000	305.2000	12.5000	4.10
292.3726	270.0000	22.3726	8.29
265.0608	254.6000	10.4608	4.11

AVG. ØF HØURLY PERCENT ERRØRS= 5.61

PERCENT ERRØR FØR TØTAL DAILY PØWER= 102.87



Predicted and Actual
Friday 6 February 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR FRI 6 FEB 76 ****

PREDICTION USES THUR 5 FEB 76 AS BASE DAY.

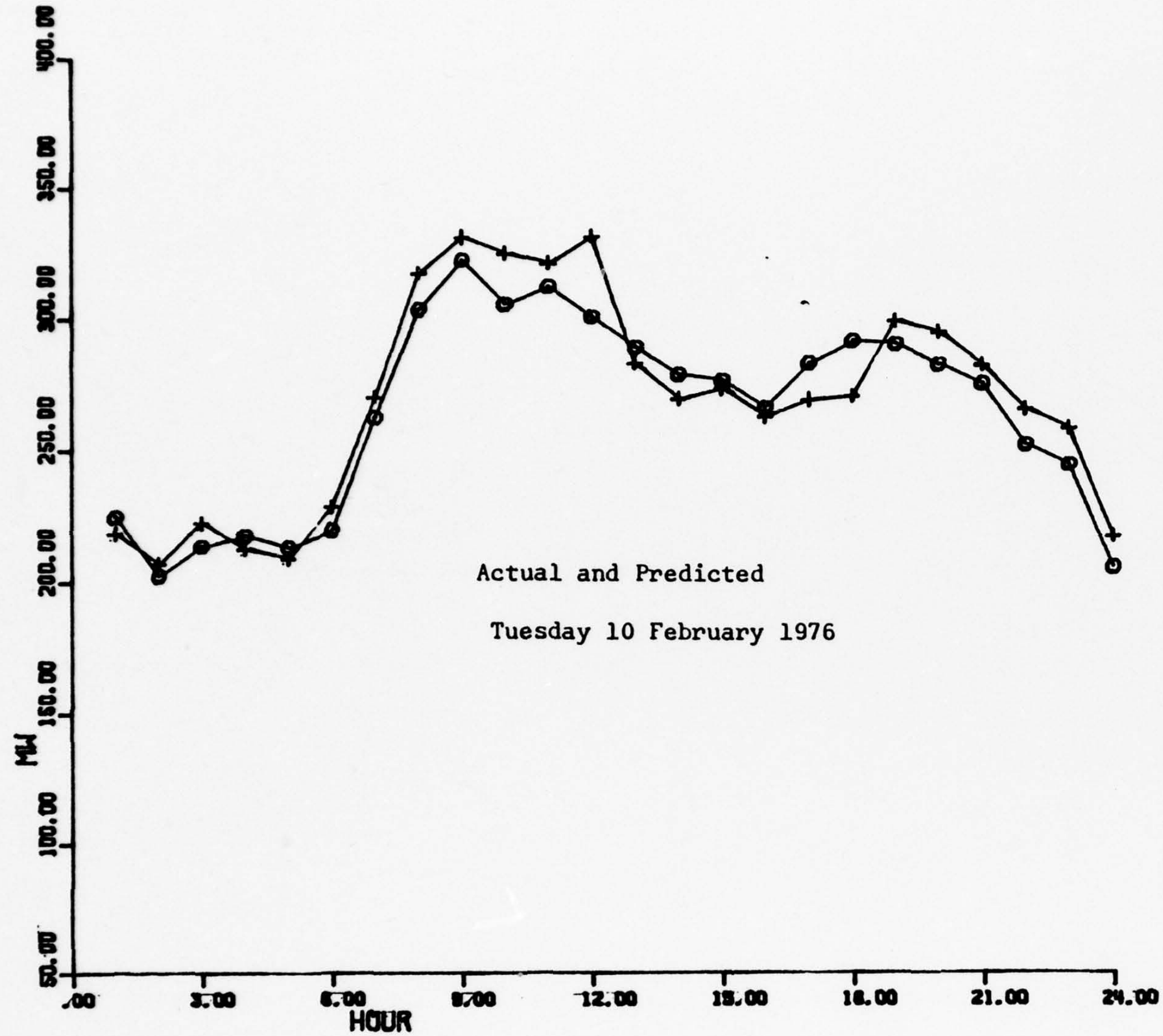
GAIN BASED ON WED 4 FEB 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
243.6500	221.1000	22.5500	10.20
239.0000	209.7000	29.3000	13.97
229.5000	224.9000	4.6000	2.05
237.0000	215.4000	21.6000	10.03
236.1900	211.7000	24.4900	11.57
236.8333	230.1000	6.7333	2.93
294.6001	272.6001	22.0000	8.07
333.2998	320.0000	13.2998	4.16
338.6899	333.5000	5.1899	1.56
334.4373	327.3000	7.1372	2.18
329.6831	323.3999	6.2832	1.94
317.1055	333.7000	-16.5945	4.97
291.3333	313.3999	-22.0667	7.04
292.0293	299.7000	-7.6707	2.56
289.8665	303.5000	-13.6335	4.49
286.0054	293.0000	-6.9946	2.39
297.3411	299.3000	-1.9590	.65
316.2266	305.6001	10.6265	3.48
321.5498	329.1001	-7.5503	2.29
333.1714	325.0000	8.1714	2.51
303.3767	312.3999	-9.0232	2.89
289.3401	295.5000	-6.1599	2.08
272.8572	258.1001	-15.2429	5.29
257.7000	247.7000	10.0000	4.04

AVG. OF HOURLY PERCENT ERRORS= 4.72

PERCENT ERROR FOR TOTAL DAILY POWER= 98.77


Actual and Predicted
Tuesday 10 February 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTIØN FØR TUES 10 FEB 76 ****

PREDICTIØN USES FRI 6 FEB 76 AS BASE DAY.

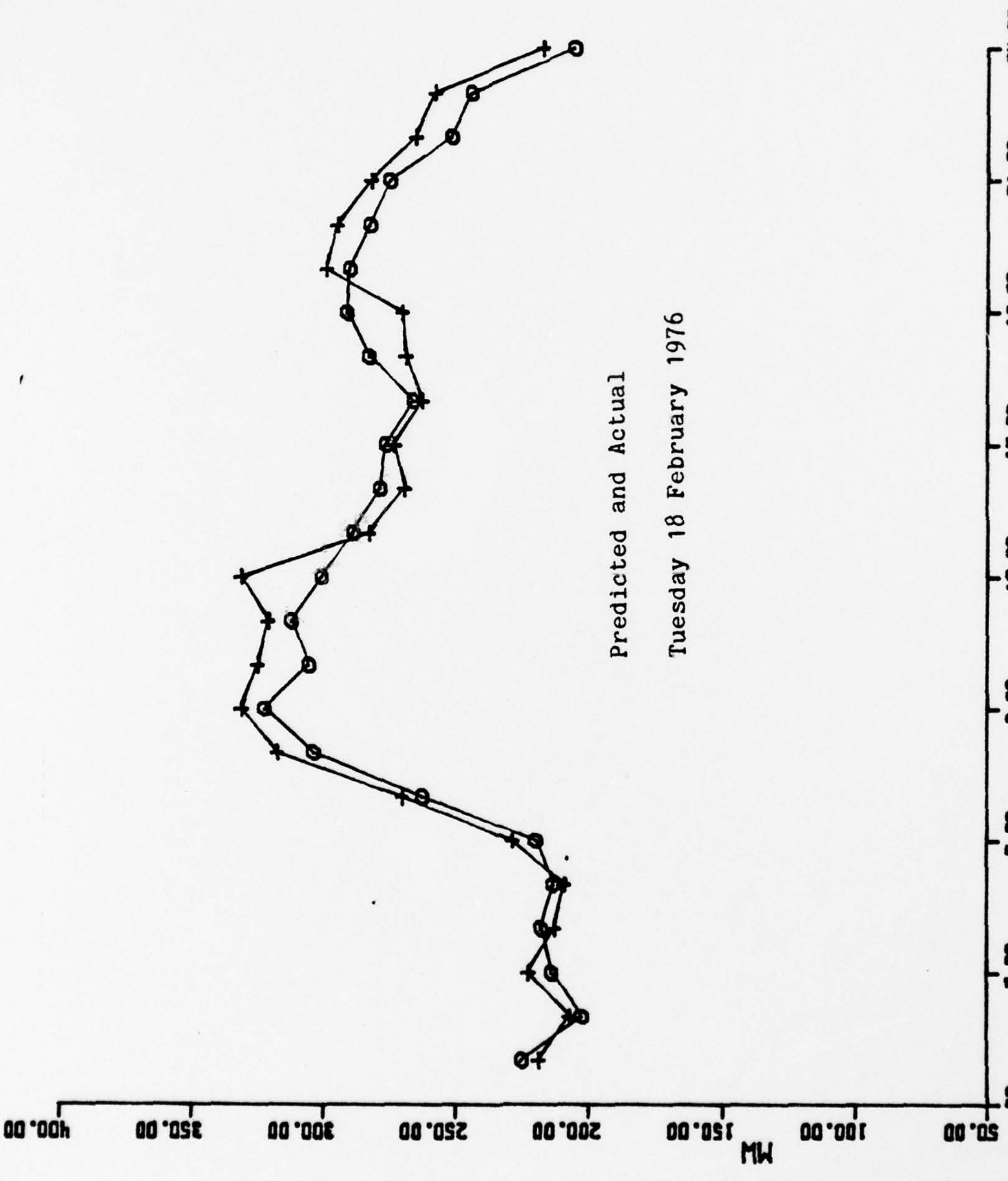
GAIN BASED ØN THUR 5 FEB 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
218.1000	224.5000	-6.4000	2.85
206.7000	201.9000	4.8000	2.38
222.2000	213.3000	8.9000	4.17
212.4000	217.1000	-4.7000	2.16
208.7000	212.8000	-4.1000	1.93
228.1800	219.2000	8.9800	4.10
269.6001	261.8000	7.8000	2.98
317.0000	303.0000	14.0000	4.62
330.5000	321.7000	8.8000	2.74
324.3000	304.8000	19.5000	6.40
320.3999	311.3999	9.0000	2.89
330.7000	299.8999	30.8000	10.27
282.3999	288.1001	-5.7002	1.98
268.7000	277.7000	-9.0000	3.24
272.5000	275.3999	-2.8999	1.05
262.0000	265.3000	-3.3000	1.24
268.3000	282.1001	-13.8000	4.89
269.6404	290.3999	-20.7595	7.15
298.1001	289.2000	8.9001	3.08
294.0000	281.5000	12.5000	4.44
281.3999	274.0000	7.3999	2.70
264.5000	250.9000	13.6000	5.42
257.1001	243.3000	13.8001	5.67
216.7000	204.6000	12.1000	5.91

AVG. ØF HØURLY PERCENT ERRØRS= 3.93

PERCENT ERRØR FØR TØTAL DAILY PØWER= 98.28


Predicted and Actual
Tuesday 18 February 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTIØN FØR WED 18 FEB 76 ****

PREDICTIØN USES TUES 17 FEB 76 AS BASE DAY.

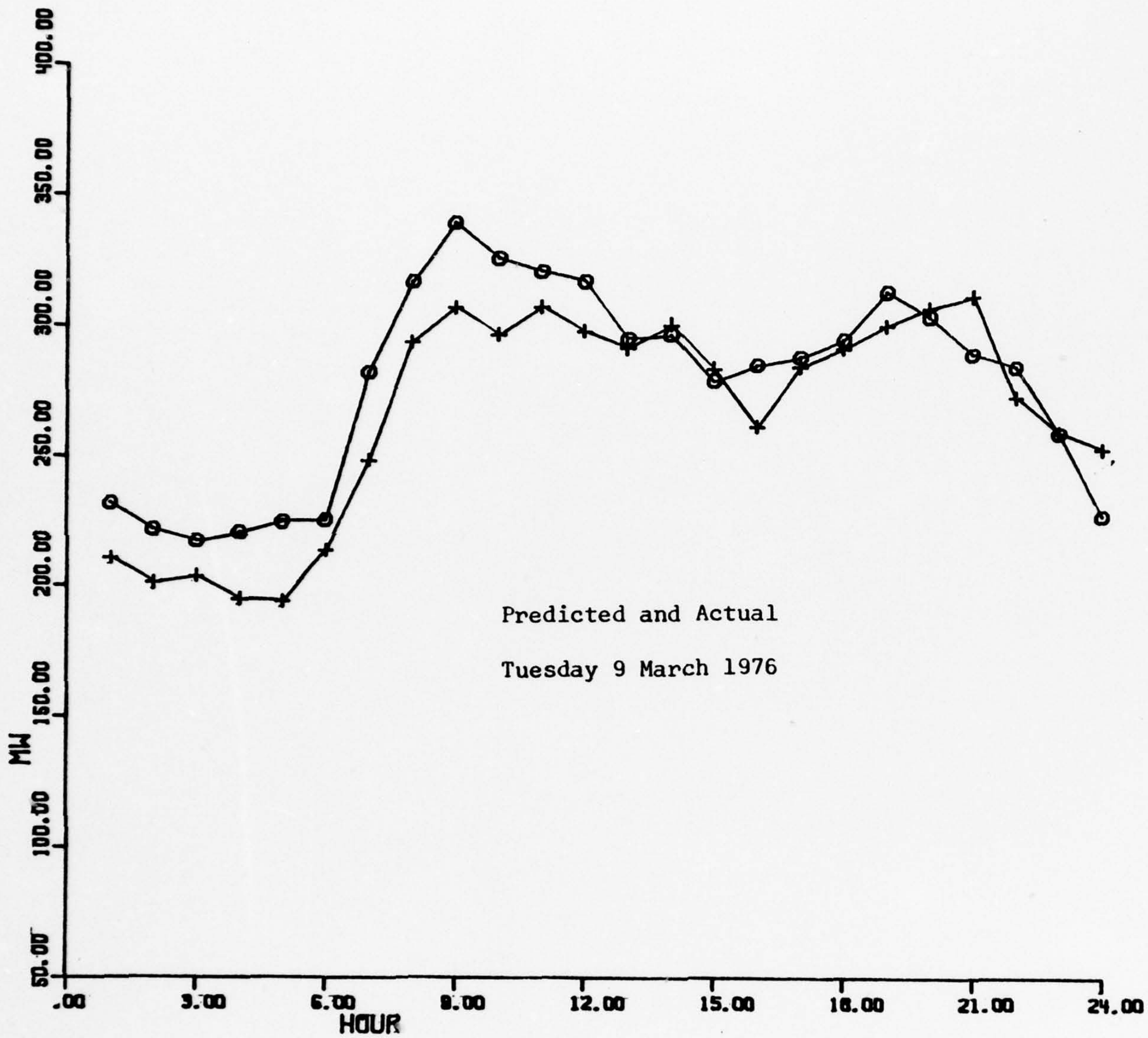
GAIN BASED ØN MØN 16 FEB 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
187.1667	201.7000	-14.5333	7.21
189.0000	189.7000	-.7000	.37
173.3571	190.7000	-17.3429	9.09
175.4857	181.4000	-5.9143	3.26
169.7167	194.7000	-24.9833	12.83
195.6000	198.7000	-3.1000	1.56
218.6000	223.9000	-5.3000	2.37
272.8000	281.0000	-8.2000	2.92
304.8999	305.1001	-.2002	.07
294.2400	308.3999	-14.1599	4.59
309.3999	306.6001	2.7998	.91
303.1001	317.1001	-14.0000	4.42
297.8999	303.1001	-5.2002	1.72
308.3999	307.2000	1.2000	.39
296.5000	308.6001	-12.1001	3.92
294.0000	293.3000	.7000	.24
299.2000	301.3999	-2.2000	.73
309.0000	306.8999	2.1001	.68
310.8999	309.3999	1.5000	.48
301.2000	303.3999	-2.2000	.73
296.2000	291.3999	4.8000	1.65
272.7000	267.6001	5.0999	1.91
255.3000	244.5000	10.8000	4.42
229.9800	231.0000	-1.0200	.44

AVG. ØF HØURLY PERCENT ERRØRS= 2.79

PERCENT ERRØR FØR TØTAL DAILY PØWER= 101.63



Predicted and Actual

Tuesday 9 March 1976

BEST AVAILABLE COPY

PREDICTIØN FØR TUE 9 MAR 76 ****

PREDICTIØN USES FRI 5 MAR 76 AS BASE DAY.

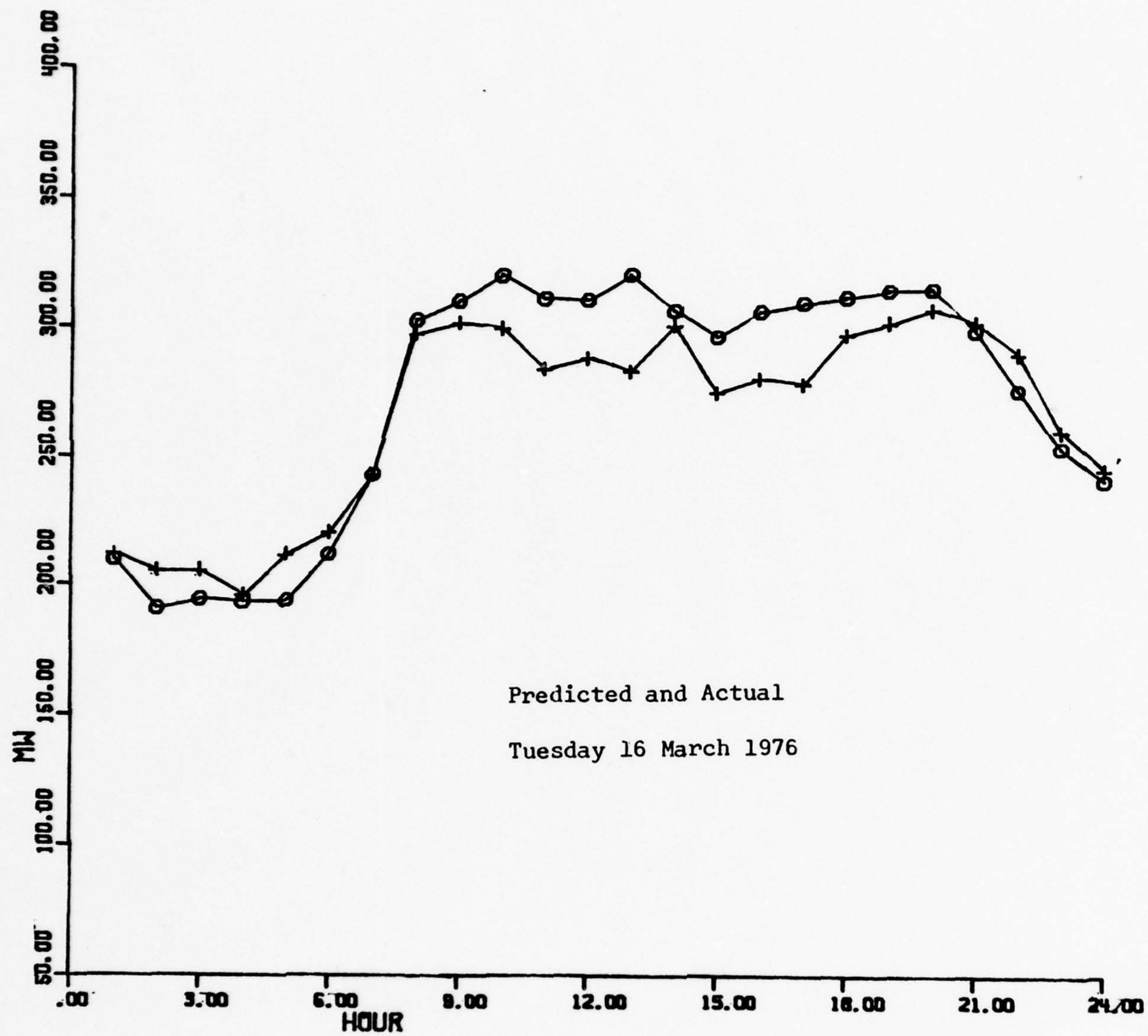
GAIN BASED ØN THUR 4 MAR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
210.5000	231.4000	-20.9000	9.03
201.0000	221.4000	-20.4000	9.21
203.6000	216.9000	-13.3000	6.13
194.7000	220.2000	-25.5000	11.58
194.0000	224.4000	-30.4000	13.55
213.5000	224.9000	-11.4000	5.07
248.2000	281.8000	-33.6001	11.92
293.1001	316.0000	-22.8999	7.25
306.3999	338.3999	-32.0000	9.46
296.2000	325.1001	-28.9001	8.89
306.6997	320.1001	-13.4004	4.19
297.4331	316.3999	-18.9668	5.99
291.2708	294.8000	-3.5293	1.20
300.2478	296.3000	3.9478	1.33
283.2998	278.5000	4.7998	1.72
261.1543	284.6001	-23.4458	8.24
284.1799	287.6001	-3.4202	1.19
291.2000	294.2000	-3.0000	1.02
299.5259	312.3999	-12.8740	4.12
306.5000	303.0000	3.5000	1.16
310.7329	288.7000	22.0330	7.63
272.3130	283.7000	-11.3870	4.01
258.9531	258.3999	.5532	.21
252.5692	226.7000	25.8692	11.41

AVG. ØF HØURLY PERCENT ERRØRS= 6.06

PERCENT ERRØR FØR TØTAL DAILY PØWER= 104.21


MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR
Predicted and Actual
Tuesday 16 March 1976

BEST AVAILABLE COPY

PREDICTION FOR TUE 16 MAR 76 ****

PREDICTION USES FRI 12 MAR 76 AS BASE DAY.

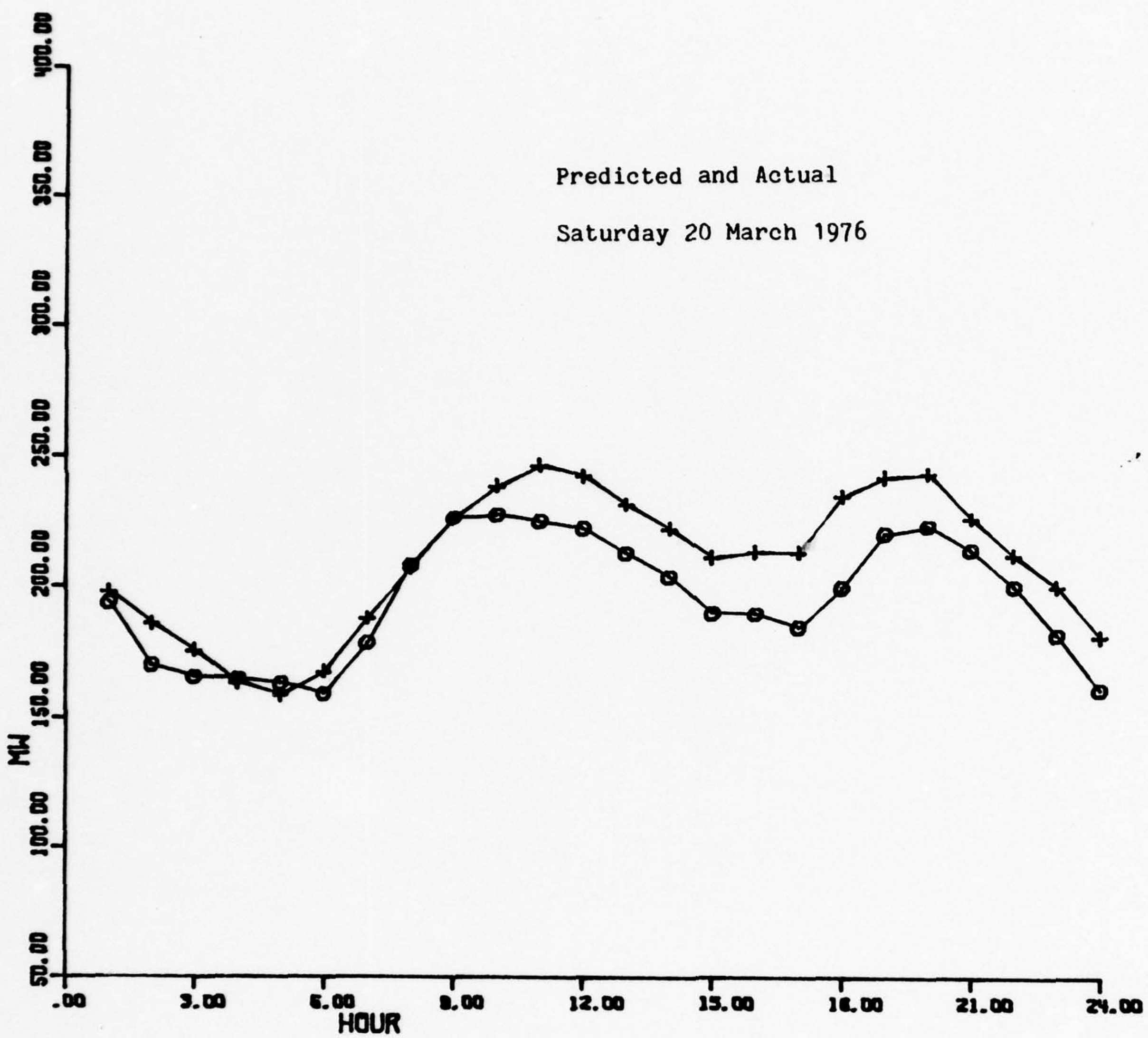
GAIN BASED ON THUR 11 MAR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
211.7000	209.6000	2.1000	1.00
205.2000	190.4000	14.8000	7.77
205.3000	194.1000	11.2000	5.77
195.7789	193.1000	2.6789	1.39
211.4000	193.5000	17.9000	9.25
220.0000	211.6000	8.4000	3.97
242.3200	242.6000	-.2800	.12
296.6477	302.0000	-5.3523	1.77
301.1350	309.5000	-8.3650	2.70
299.0000	319.3000	-20.3000	6.36
283.5000	310.5000	-27.0000	8.70
287.7000	309.8999	-22.2000	7.16
282.8000	319.7000	-36.8999	11.54
300.3501	306.0000	-5.6499	1.85
274.3000	295.7000	-21.3999	7.24
279.7871	305.6001	-25.8130	8.45
277.8572	308.8999	-31.0427	10.05
296.6165	311.0000	-14.3835	4.62
301.2000	313.6001	-12.4001	3.95
306.3999	314.3000	-7.9001	2.51
301.3401	297.8999	3.4402	1.15
289.3000	275.3000	14.0000	5.09
259.5571	253.1000	6.4571	2.55
244.4000	240.0000	4.4000	1.83

AVG. OF HOURLY PERCENT ERRORS= 4.87

PERCENT ERROR FOR TOTAL DAILY POWER= 102.41


Predicted and Actual
Saturday 20 March 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
12.00
15.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR SAT 20 MAR 76 ****

PREDICTION USES SAT 13 MAR 76 AS BASE DAY.

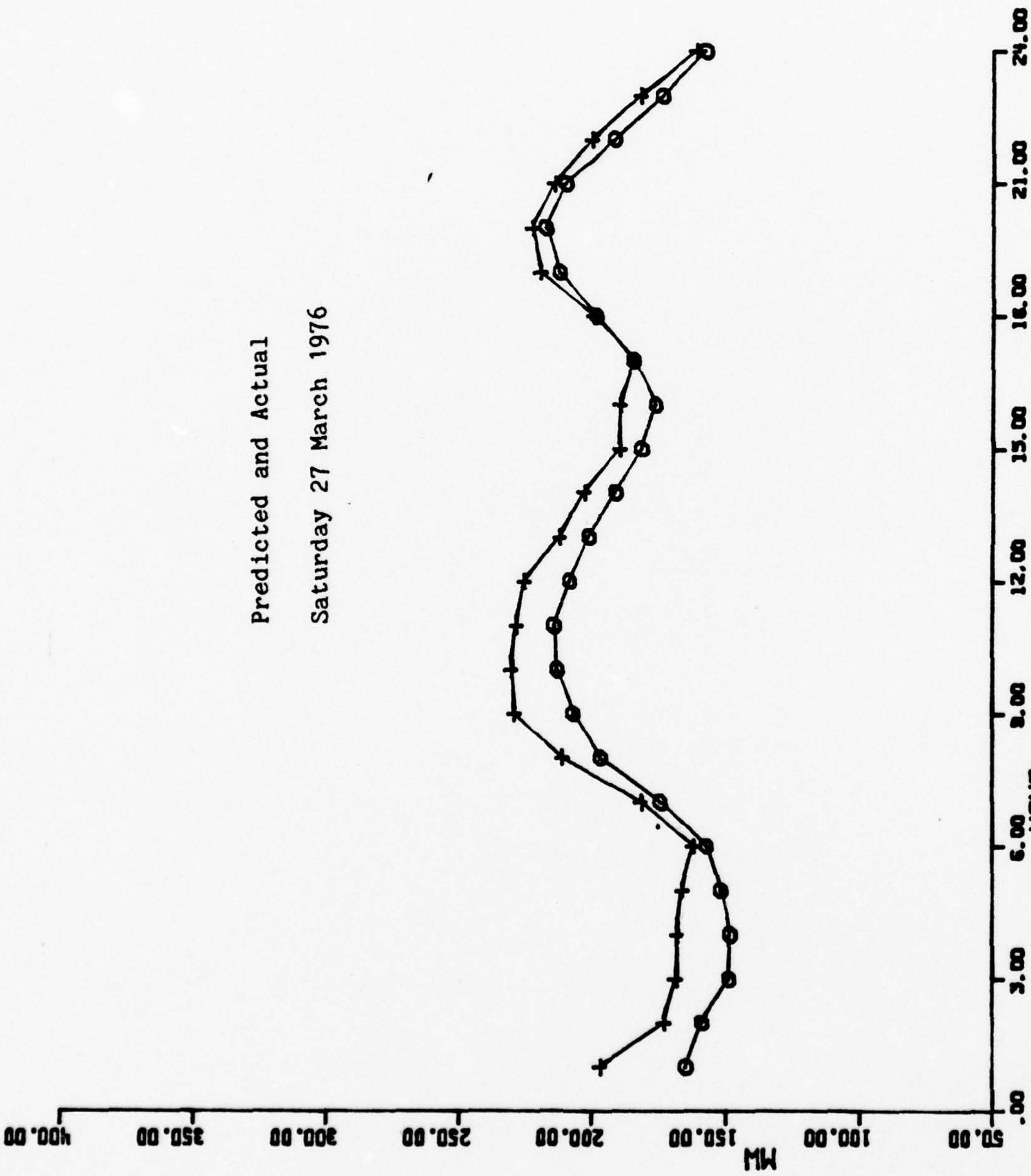
GAIN BASED ON SUN 14 MAR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
197.6000	193.4000	4.2000	2.17
185.6000	169.7000	15.9000	9.37
175.5000	165.2000	10.3000	6.23
163.1375	164.7000	-1.5625	.95
158.6571	162.9000	-4.2429	2.60
167.4000	158.9000	8.5000	5.35
187.7000	178.1000	9.6000	5.39
207.0000	207.8000	-.8000	.38
225.9000	225.9000	.0000	.00
238.5000	227.1000	11.4000	5.02
246.5000	224.8000	21.7000	9.65
242.2000	221.9000	20.3000	9.15
231.3000	212.6000	18.7000	8.80
222.0000	203.4000	18.6000	9.14
211.0000	189.5000	21.5000	11.35
213.2000	189.4000	23.8000	12.57
213.1000	184.3000	28.8000	15.63
234.4000	199.3000	35.1000	17.61
241.8999	220.0000	21.8999	9.95
243.3000	223.0000	20.3000	9.10
226.0000	213.7000	12.3000	5.76
212.1000	199.9000	12.2000	6.10
199.8000	181.6000	18.2000	10.02
180.8000	160.8000	20.0000	12.44

AVG. OF HOURLY PERCENT ERRORS= 7.70

PERCENT ERROR FOR TOTAL DAILY POWER= 93.10



Predicted and Actual

Saturday 27 March 1976

BEST AVAILABLE COPY

PREDICTION FOR SAT 27 MAR 76 ****

PREDICTION USES SAT 20 MAR 76 AS BASE DAY.

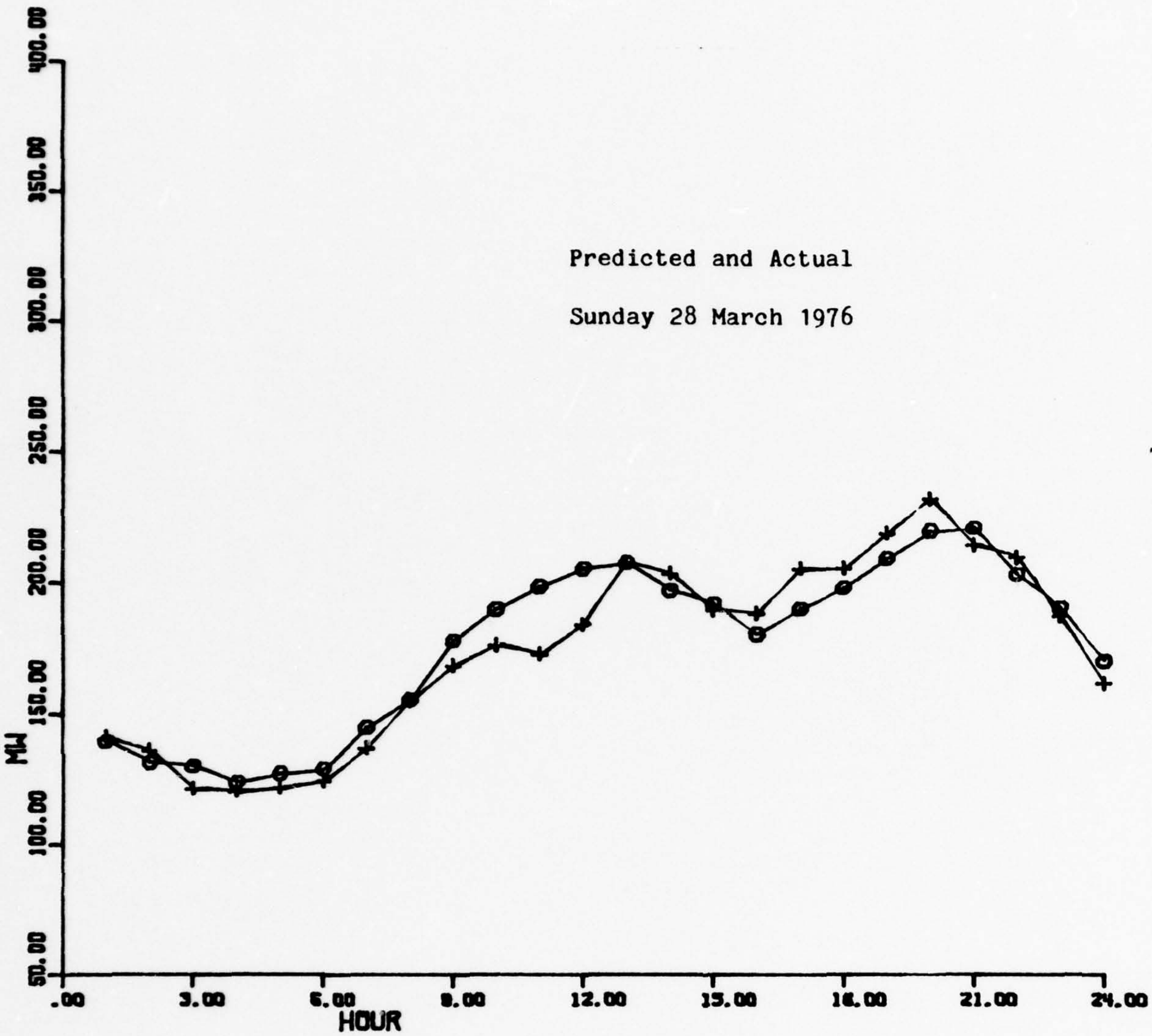
GAIN BASED ON SUN 21 MAR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
196.4000	164.4000	32.0000	19.46
172.7000	158.5000	14.2000	8.96
168.2000	148.4000	19.8000	13.34
167.7000	147.8000	19.9000	13.46
165.9000	151.4000	14.5000	9.58
161.9000	155.7000	5.2000	3.32
181.1000	173.7000	7.4000	4.26
210.8000	196.1000	14.7000	7.50
228.9000	206.4000	22.5000	10.90
230.1000	212.5000	17.6000	8.28
227.8000	213.6000	14.2000	6.65
224.9000	207.7000	17.2000	8.28
211.6000	200.5000	11.1000	5.54
202.4000	190.5000	11.9000	6.25
189.2400	180.9000	8.3400	4.61
189.1600	175.7000	13.4600	7.66
183.6900	183.8000	-.1100	.06
199.1300	197.8000	1.3300	.67
219.0000	211.5000	7.5000	3.55
222.1500	216.8000	5.3500	2.47
213.6937	209.1000	4.5937	2.20
199.4200	190.8000	8.6200	4.52
181.3800	173.1000	8.2800	4.78
160.6857	157.0000	3.6857	2.35

AVG. OF HOURLY PERCENT ERRORS= 6.61

PERCENT ERROR FOR TOTAL DAILY POWER= 93.98


Predicted and Actual
Sunday 28 March 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR SUN 28 MAR 76 ****

PREDICTION USES SUN 21 MAR 76 AS BASE DAY.

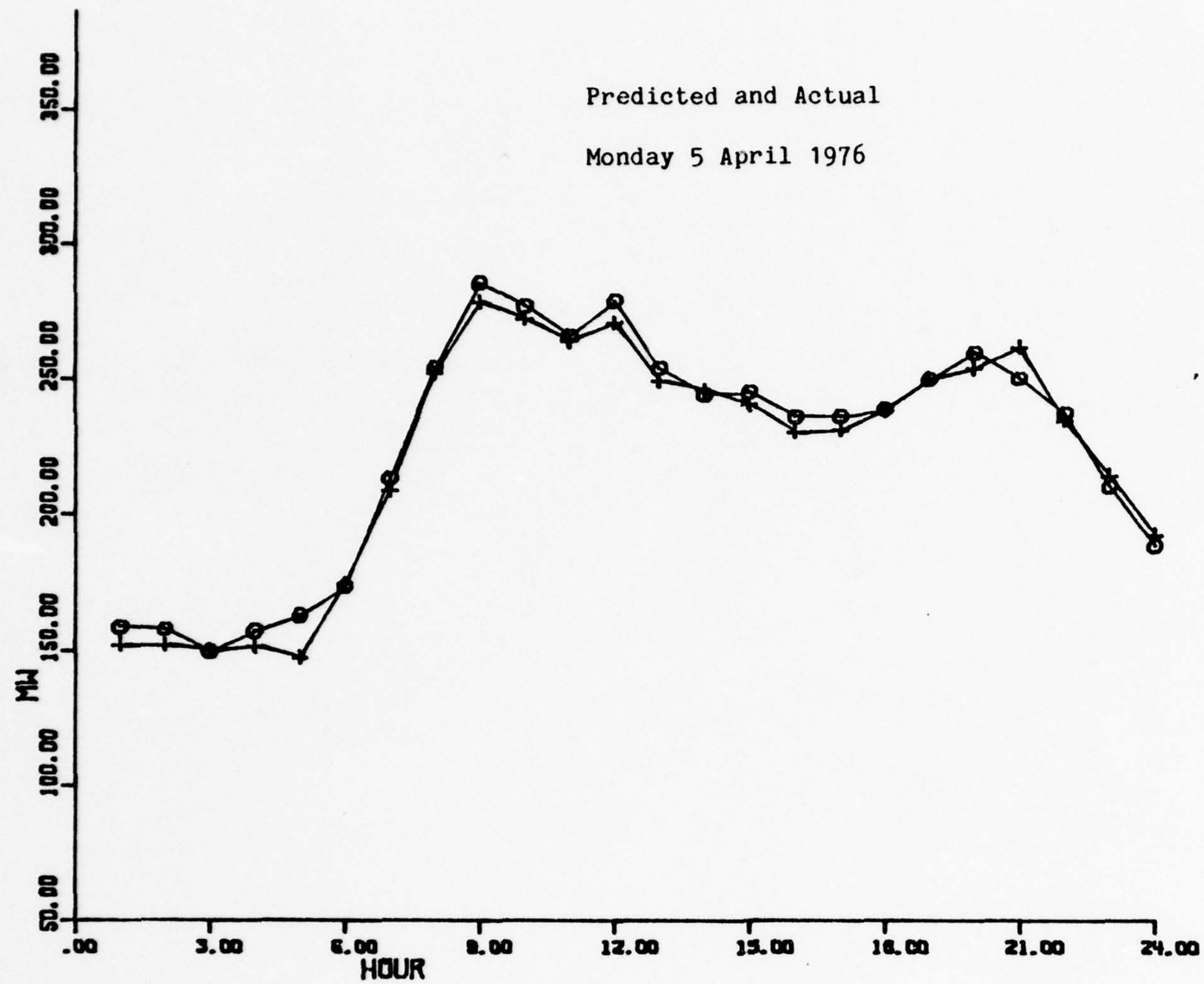
GAIN BASED ON SAT 20 MAR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
140.8000	139.6000	1.2000	.86
136.1000	131.3000	4.8000	3.66
121.5000	130.1000	-8.6000	6.61
120.3000	123.7000	-3.4000	2.75
121.8000	127.0000	-5.2000	4.09
124.2000	128.8000	-4.6000	3.57
137.2000	144.8000	-7.6000	5.25
154.9000	155.5000	-.6000	.39
168.4000	177.7000	-9.3000	5.23
176.1000	189.5000	-13.4000	7.07
172.8000	198.2000	-25.4000	12.82
184.0000	204.9000	-20.9000	10.20
207.5000	207.0000	.5000	.24
203.1000	196.6000	6.5000	3.31
189.2400	191.6000	-2.3600	1.23
187.9600	180.0000	7.9600	4.42
205.0400	189.6000	15.4400	8.14
205.0800	197.6000	7.4800	3.79
218.5000	208.7000	9.8000	4.70
231.5000	219.2000	12.3000	5.61
213.8875	220.4000	-6.5125	2.95
209.0200	202.5000	6.5200	3.22
186.8800	189.8000	-2.9200	1.54
161.6000	169.8000	-8.2000	4.83

AVG. OF HOURLY PERCENT ERRORS= 4.44

PERCENT ERROR FOR TOTAL DAILY POWER= 101.11


Predicted and Actual
Monday 5 April 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR MON 5 APR 76 ****

PREDICTION USES MON 29 MAR 76 AS BASE DAY.

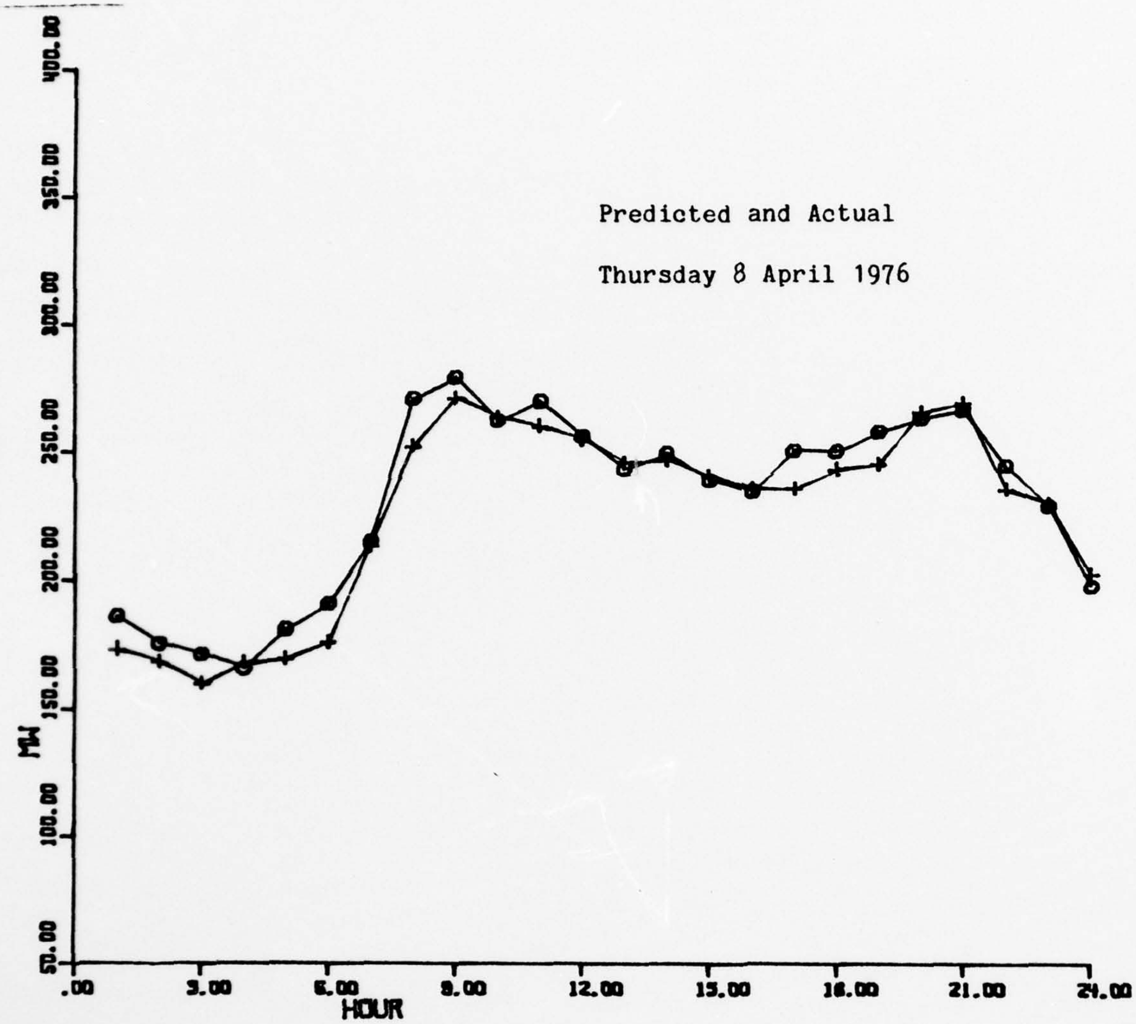
GAIN BASED ON FRI 2 APR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
152.1000	158.5000	-6.4000	4.04
152.0000	157.7000	-5.7000	3.61
150.0000	149.5000	.5000	.33
151.5000	157.0000	-5.5000	3.50
147.4100	162.6000	-15.1900	9.34
174.4100	173.3000	1.1100	.64
208.5200	213.0000	-4.4800	2.10
251.8000	253.8000	-2.0000	.79
278.1399	285.1001	-6.9602	2.44
272.1001	276.5000	-4.3999	1.59
263.6997	265.3999	-1.7002	.64
270.6001	278.5000	-7.8999	2.84
248.8667	253.4000	-4.5333	1.79
245.5400	243.8000	1.7400	.71
240.0000	244.4000	-4.4000	1.80
230.1000	235.5000	-5.4000	2.29
231.1000	235.7000	-4.6000	1.95
238.2000	238.5000	-.3000	.13
249.7000	249.4000	.3000	.12
253.5002	259.1001	-5.5999	2.16
261.3198	249.6000	11.7198	4.70
234.2000	236.8000	-2.6000	1.10
213.9000	210.0000	3.9000	1.86
192.3000	188.2000	4.1000	2.18

AVG. OF HOURLY PERCENT ERRORS= 2.19

PERCENT ERROR FOR TOTAL DAILY POWER= 101.21


Predicted and Actual
Thursday 8 April 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTIØN FØR THUR 8 APR 76 ****

PREDICTIØN USES WED 7 APR 76 AS BASE DAY.

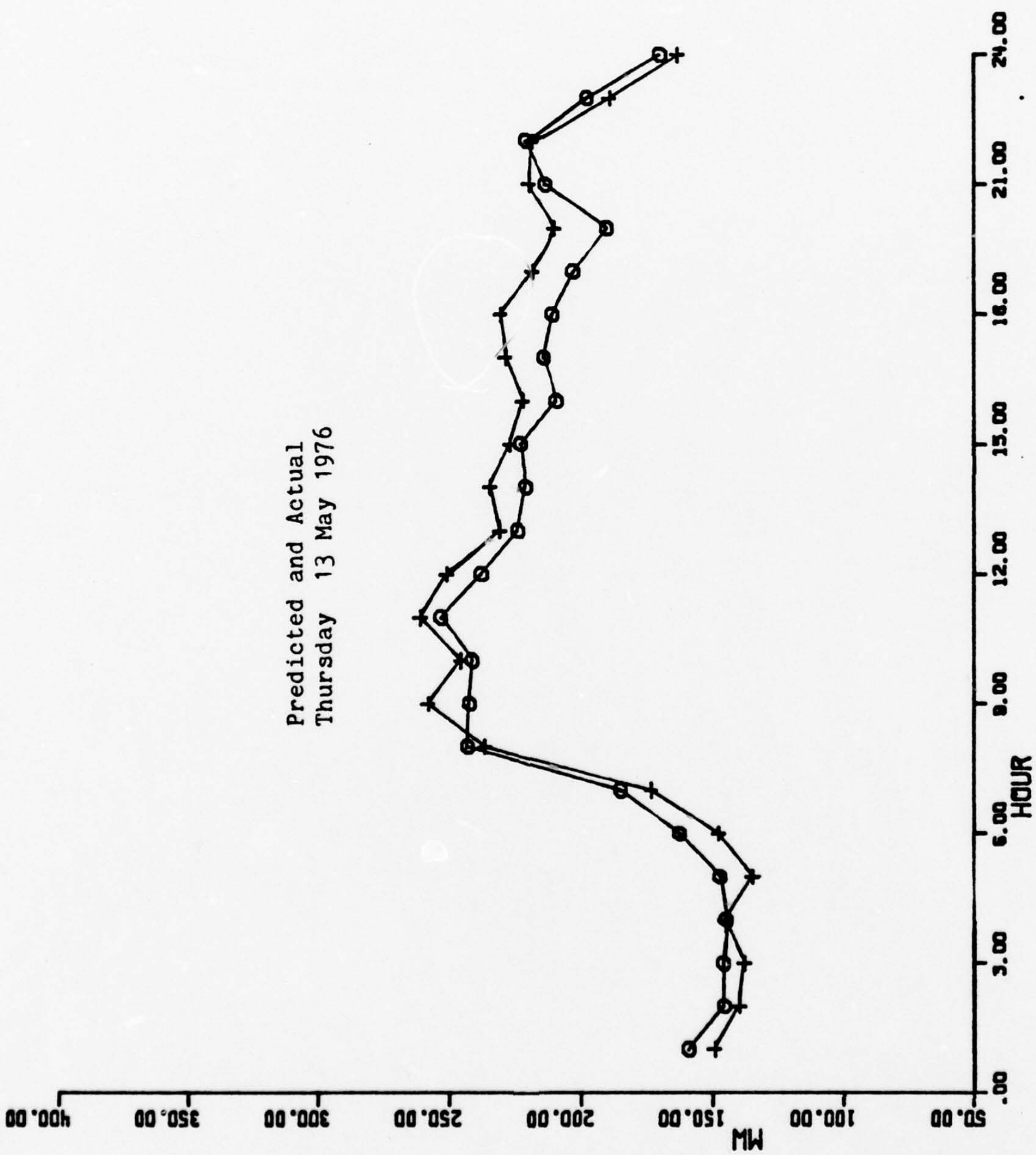
GAIN BASED ØN TUE 6 APR 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
173.3000	185.9000	-12.6000	6.78
168.6286	175.5000	-6.8714	3.92
160.2545	171.3000	-11.0455	6.45
168.1000	165.8000	2.3000	1.39
169.7667	180.8000	-11.0333	6.10
176.2000	190.7000	-14.5000	7.60
213.2333	214.9000	-1.6667	.78
252.2778	270.6001	-18.3223	6.77
271.0999	278.8999	-7.8000	2.80
263.5427	262.0000	1.5427	.59
260.0667	269.7000	-9.6333	3.57
254.8000	256.0000	-1.2000	.47
245.8636	243.3000	2.5636	1.05
246.7750	249.4000	-2.6250	1.05
240.4000	238.9000	1.5000	.63
235.7667	234.4000	1.3667	.58
235.8000	250.4000	-14.6000	5.83
243.2000	250.1000	-6.9000	2.76
245.3000	257.8000	-12.5001	4.85
265.7112	263.1001	2.6111	.99
269.3000	266.2000	3.1001	1.16
235.5428	244.4000	-8.8571	3.62
229.6857	228.8000	.8857	.39
202.5000	197.7000	4.9000	2.48

AVG. ØF HØURLY PERCENT ERRØRS= 3.03

PERCENT ERRØR FØR TØTAL DAILY PØWER= 102.20


Predicted and Actual
Thursday 13 May 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR THUR 13 MAY 76 ****

PREDICTION USES WED 12 MAY 76 AS BASE DAY.

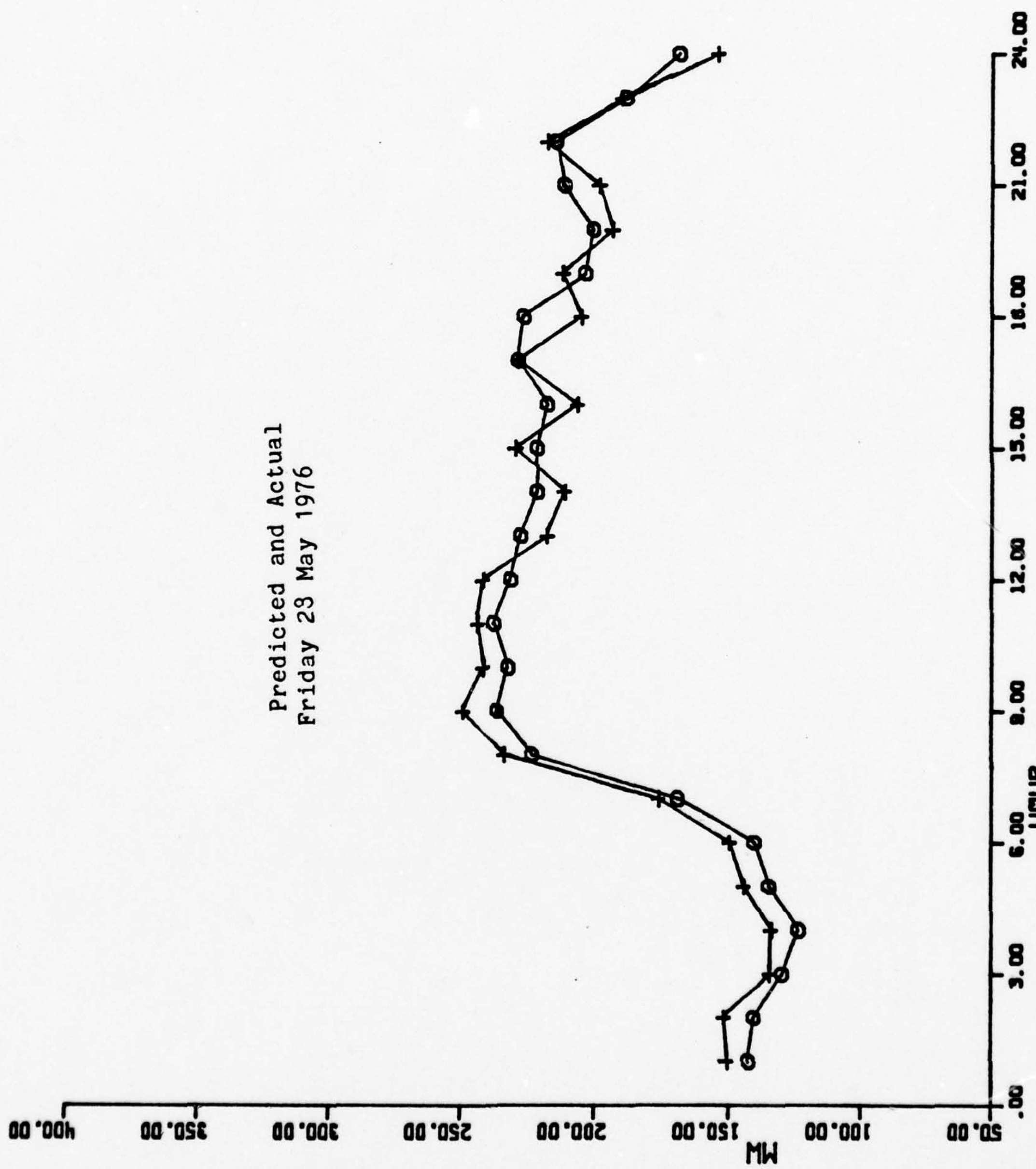
GAIN BASED ON TUE 11 MAY 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
149.4000	159.1000	-9.7000	6.10
139.9000	145.6000	-5.7000	3.91
138.0000	145.8000	-7.8000	5.35
145.4000	144.8000	.6000	.41
135.1000	147.1000	-12.0000	8.16
147.8800	162.5000	-14.6200	9.00
173.2000	184.9000	-11.7000	6.33
236.5375	242.8000	-6.2625	2.58
258.0356	242.2000	15.8356	6.54
245.4400	241.1000	4.3400	1.80
260.9780	253.1000	7.8780	3.11
251.0000	237.6000	13.4000	5.64
230.8913	223.9000	6.9913	3.12
234.5353	220.8000	13.7353	6.22
226.9800	222.8000	4.1800	1.88
222.1500	209.2000	12.9500	6.19
228.7200	214.0000	14.7200	6.88
230.6000	210.7000	19.9000	9.44
218.4200	202.9000	15.5200	7.65
210.2625	190.1000	20.1625	10.61
219.7059	213.5000	6.2059	2.91
218.7400	220.7000	-1.9600	.89
189.1059	197.6000	-8.4941	4.30
163.2727	169.7000	-6.4273	3.79

AVG. OF HOURLY PERCENT ERRORS= 5.12

PERCENT ERROR FOR TOTAL DAILY POWER= 98.53


Predicted and Actual
Friday 23 May 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR FRI 28 MAY 76 ****

PREDICTION USES THUR 27 MAY 76 AS BASE DAY.

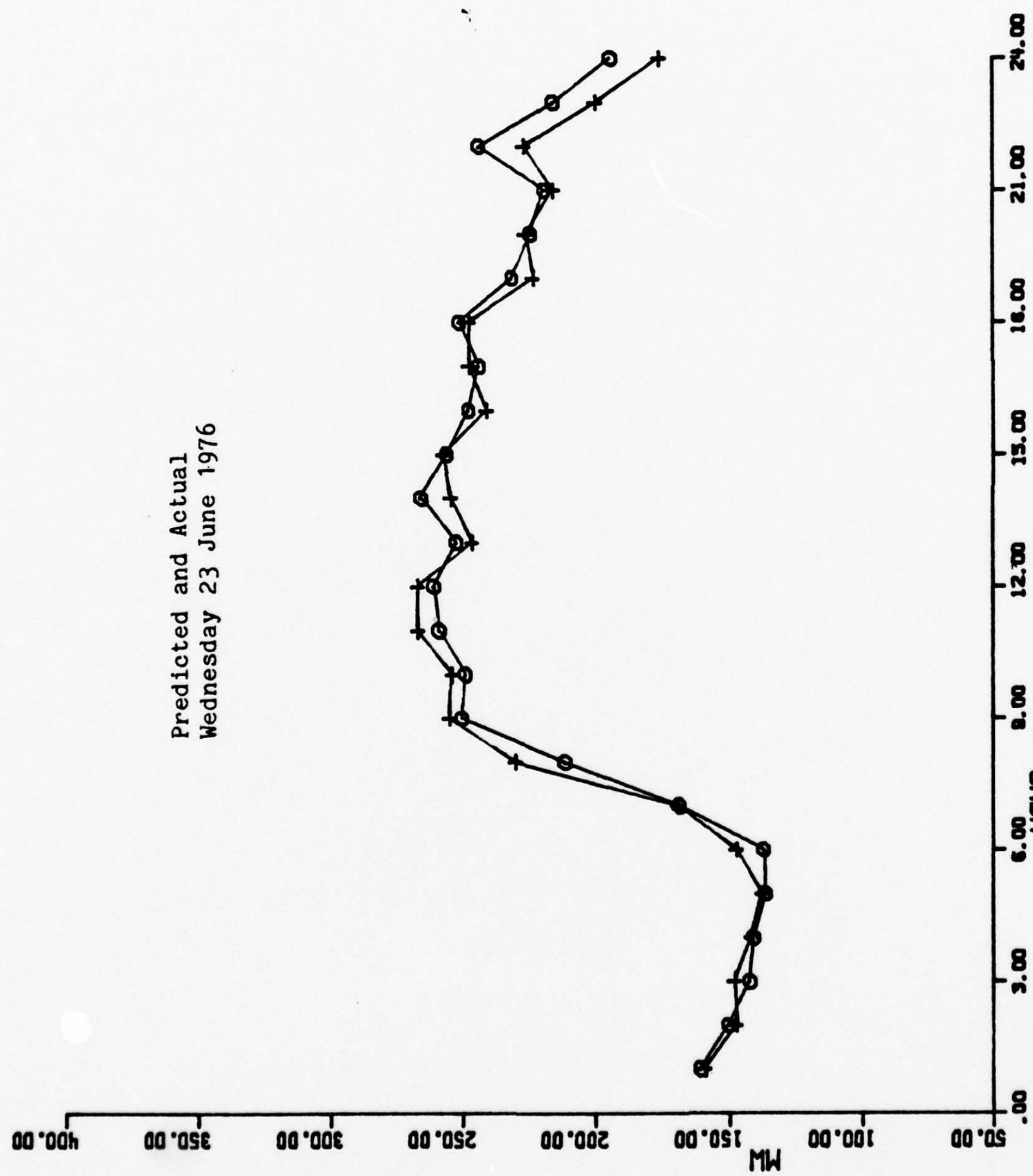
GAIN BASED ON WED 26 MAY 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
150.2600	142.2000	8.0600	5.67
151.5750	140.1000	11.4750	8.19
134.1000	129.4000	4.7000	3.63
133.8000	123.3000	10.5000	8.52
144.0000	134.3000	9.7000	7.22
149.5000	140.0000	9.5000	6.79
175.9000	168.7000	7.2000	4.27
233.2300	222.8000	10.4300	4.68
248.9000	236.0000	12.9000	5.47
241.4000	231.8000	9.6000	4.14
243.4750	237.3000	6.1750	2.60
241.3727	230.8000	10.5727	4.58
217.5818	227.1000	-9.5182	4.19
211.1000	221.1000	-10.0000	4.52
229.0077	220.7000	8.3077	3.76
205.9000	217.0000	-11.1000	5.12
228.5235	228.2000	.3235	.14
204.8294	226.1000	-21.2706	9.41
211.4706	203.1000	8.3706	4.12
193.3438	200.4000	-7.0562	3.52
198.3000	211.2000	-12.9000	6.11
217.3625	214.1000	3.2625	1.52
189.7500	188.2000	1.5500	.82
154.2000	168.4000	-14.2000	8.43

AVG. OF HOURLY PERCENT ERRORS= 4.89

PERCENT ERROR FOR TOTAL DAILY POWER= 99.01


Predicted and Actual
Wednesday 23 June 1976
MW
HOUR
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR WED 23 JUN 76 ****

PREDICTION USES TUE 22 JUN 76 AS BASE DAY.

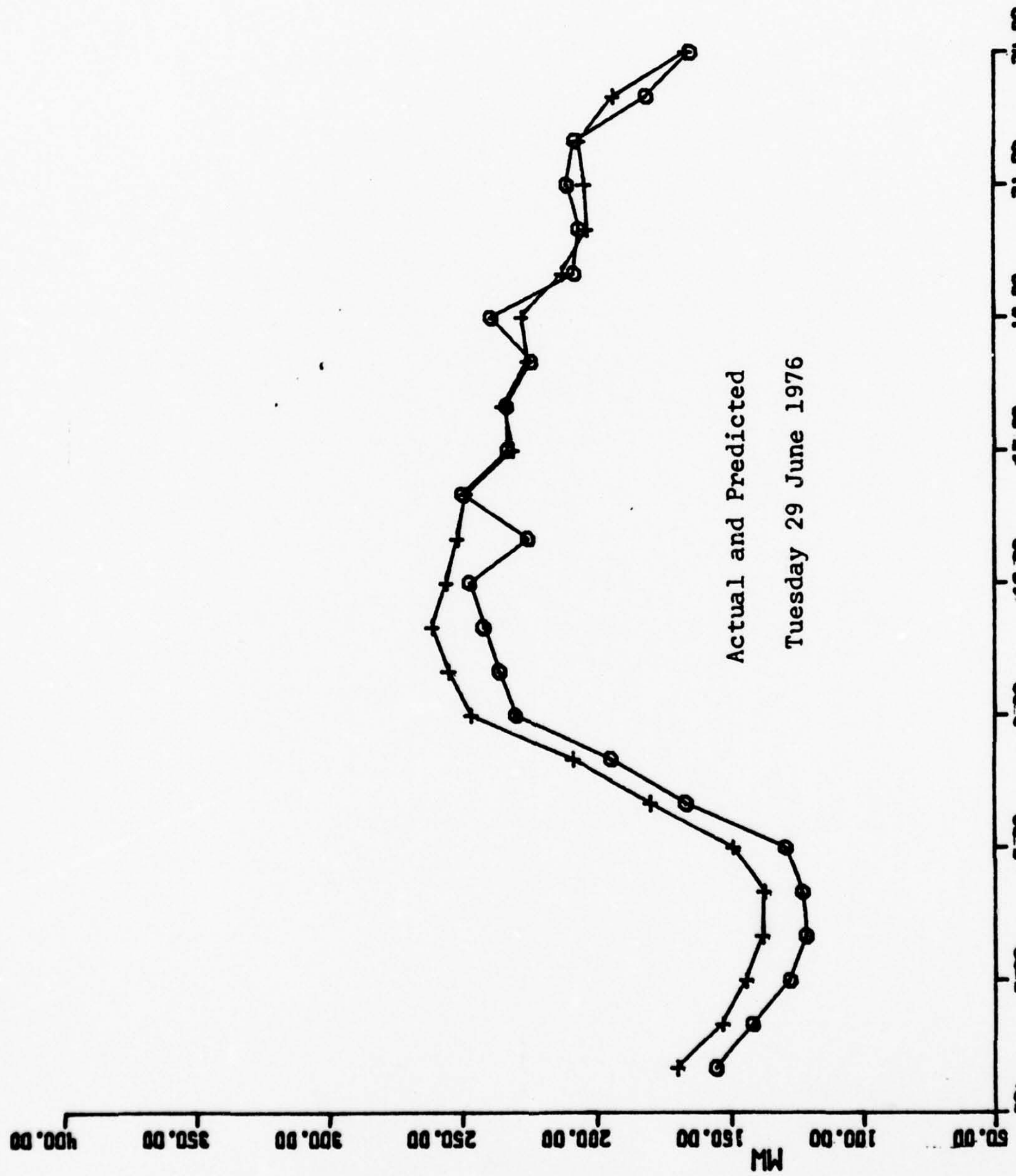
GAIN BASED ON MON 21 JUN 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
159.1000	160.5000	-1.4000	.87
147.4000	150.2000	-2.8000	1.86
148.1000	142.2000	5.9000	4.15
141.7000	140.9000	.8000	.57
137.8000	136.5000	1.3000	.95
147.5000	137.1000	10.4000	7.59
169.1000	168.4000	.7000	.42
229.7000	211.0000	18.7000	8.86
254.6000	249.7000	4.9000	1.96
253.5600	248.5000	5.0600	2.04
266.3599	258.3000	8.0598	3.12
266.4697	260.3000	6.1697	2.37
246.0000	251.7000	-5.7000	2.26
253.8997	264.8000	-10.9004	4.12
256.8000	255.3000	1.5000	.59
240.2000	247.0000	-6.8000	2.75
247.0500	243.1000	3.9500	1.62
246.9100	250.5000	-3.5900	1.43
222.7900	230.6000	-7.8100	3.39
225.5700	223.8000	1.7700	.79
215.3000	218.7000	-3.4000	1.55
226.3500	243.1000	-16.7500	6.89
199.3000	215.1000	-15.8000	7.35
175.6000	193.6000	-18.0000	9.30

AVG. OF HOURLY PERCENT ERRORS= 3.20

PERCENT ERROR FOR TOTAL DAILY POWER= 100.47


Actual and Predicted
Tuesday 29 June 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR TUE 29 JUN 76 ****

PREDICTION USES FRI 25 JUN 76 AS BASE DAY.

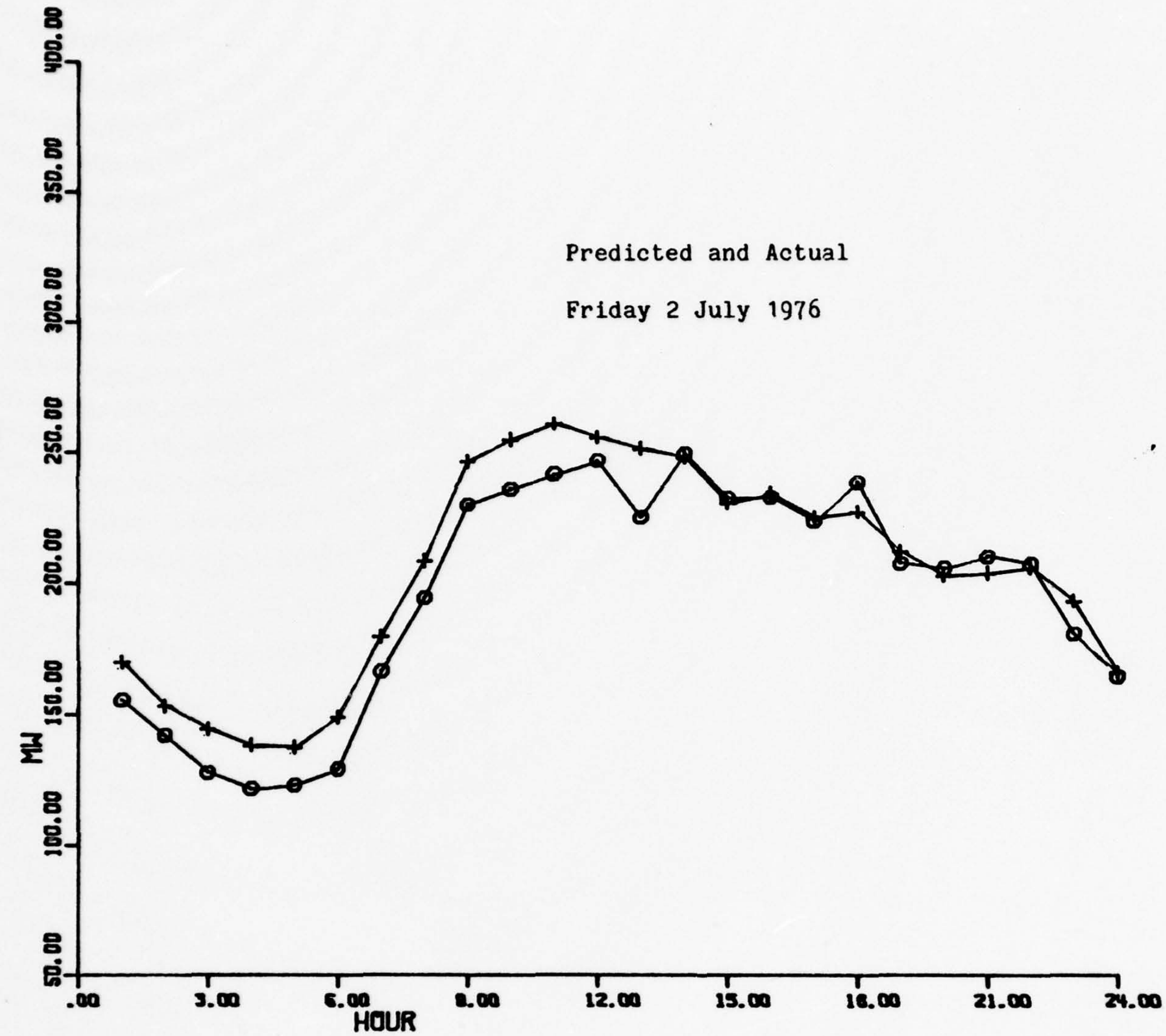
GAIN BASED ON THUR 24 JUN 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
169.8000	155.4000	14.4000	9.27
153.3000	141.9000	11.4000	8.03
144.2000	127.6000	16.6000	13.01
138.2000	121.5000	16.7000	13.74
137.3400	122.9000	14.4400	11.75
148.7700	129.0000	19.7700	15.33
179.5000	166.3000	13.2000	7.94
208.3000	194.1000	14.2000	7.32
246.1000	229.6000	16.5000	7.19
254.6500	235.4000	19.2500	8.18
260.6248	241.2000	19.4248	8.05
255.2500	246.3000	8.9500	3.63
251.1000	224.8000	26.3000	11.70
247.6333	249.0000	-1.3667	.55
230.3400	232.0000	-1.6600	.72
233.8800	232.5000	1.3800	.59
224.9462	223.3000	1.6461	.74
226.9600	238.2000	-11.2400	4.72
211.8000	207.1000	4.7000	2.27
202.8000	205.3000	-2.5000	1.22
203.6000	209.8000	-6.2000	2.96
205.8000	207.0000	-1.2000	.58
193.0000	180.5000	12.5000	6.93
165.9000	164.2000	1.7000	1.04

AVG. OF HOURLY PERCENT ERRORS= 6.14

PERCENT ERROR FOR TOTAL DAILY POWER= 95.73


Predicted and Actual
Friday 2 July 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTIØN FØR FRI 2 JUL 76 ****

PREDICTIØN USES THUR 1 JUL 76 AS BASE DAY.

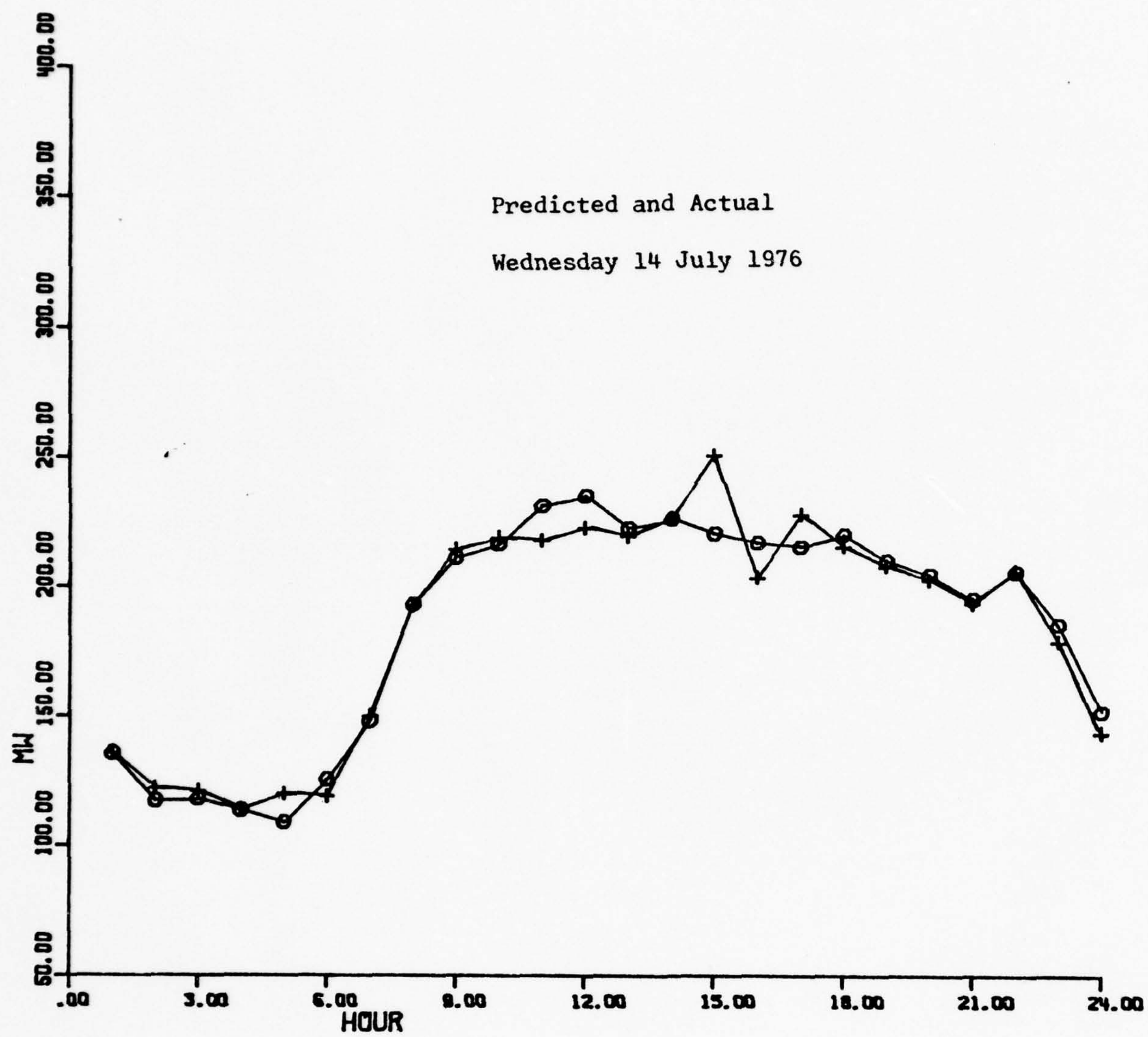
GAIN BASED ØN WED 30 JUN 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
144.7300	147.1000	-2.3700	1.61
133.6000	137.6000	-4.0000	2.91
133.3000	133.5000	-.2000	.15
131.5000	130.0000	1.5000	1.15
124.0333	126.0000	-1.9667	1.56
142.0000	132.8000	9.2000	6.93
162.8750	156.2000	6.6750	4.27
204.2800	189.1000	15.1800	8.03
237.8000	216.2000	21.6000	9.99
243.8000	229.9000	13.9000	6.05
244.3000	217.8000	26.5000	12.17
240.1000	227.2000	12.9000	5.68
243.7000	213.2000	30.5000	14.31
242.2000	224.3000	17.9000	7.98
238.4333	215.2000	23.2333	10.80
221.1538	210.0000	11.1538	5.31
232.0000	209.5000	22.5000	10.74
233.2867	219.2000	14.0867	6.43
217.9571	206.7000	11.2571	5.45
216.6000	206.3000	10.3000	4.99
220.4000	208.0000	12.4000	5.96
226.6000	197.0000	29.6000	15.03
215.0000	187.9000	27.1000	14.42
179.3000	165.5000	13.8000	8.34

AVG. ØF HØURLY PERCENT ERRØRS= 7.09

PERCENT ERRØR FØR TØTAL DAILY PØWER= 93.32


Predicted and Actual
Wednesday 14 July 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR WED 14 JUL 76 ****

PREDICTION USES TUE 13 JUL 76 AS BASE DAY.

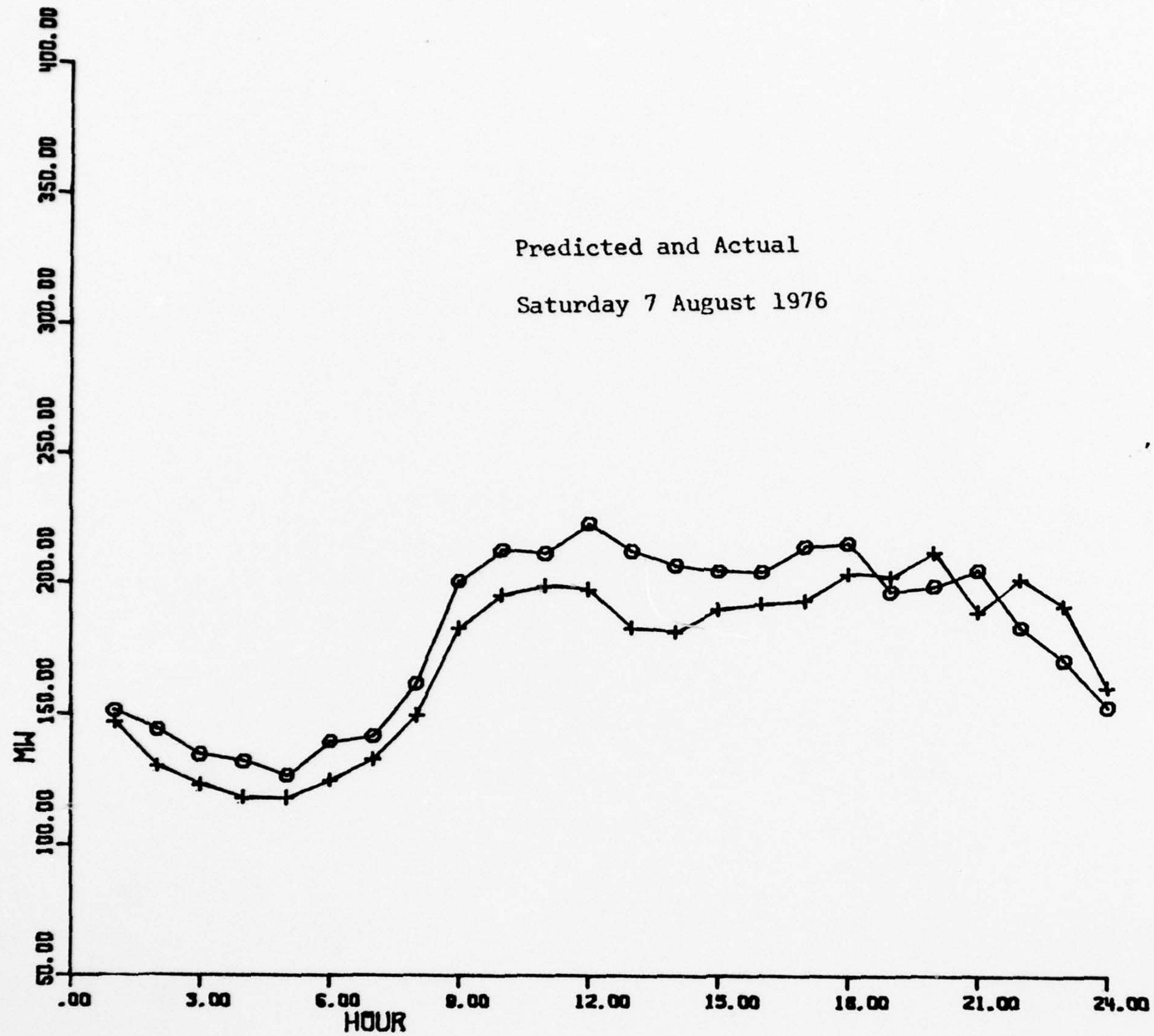
GAIN BASED ON MON 12 JUL 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
135.6000	135.3000	.3000	.22
121.9000	117.0000	4.9000	4.19
121.1000	117.7000	3.4000	2.89
113.9000	113.3000	.6000	.53
120.1000	108.9000	11.2000	10.28
118.8000	125.3000	-6.5000	5.19
150.1000	147.8000	2.3000	1.56
192.5000	192.9000	-.4000	.21
214.1750	211.0000	3.1750	1.50
218.7500	215.9000	2.8500	1.32
217.6000	230.8000	-13.2000	5.72
222.5000	234.8000	-12.3000	5.24
219.3000	222.3000	-3.0000	1.35
226.2000	225.6000	.6000	.27
250.6000	220.0000	30.6000	13.91
203.0000	216.4000	-13.4000	6.19
227.7500	214.9000	12.8500	5.98
215.0714	219.4000	-4.3286	1.97
207.5000	209.2000	-1.7000	.81
202.2000	204.1000	-1.9000	.93
193.3000	194.6000	-1.3000	.67
205.8000	205.1000	.7000	.34
178.4500	184.8000	-6.3500	3.44
143.6000	151.6000	-8.0000	5.28

AVG. OF HOURLY PERCENT ERRORS= 3.33

PERCENT ERROR FOR TOTAL DAILY POWER= 99.98


Predicted and Actual
Saturday 7 August 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR SAT 7 AUG 76 ****

PREDICTION USES SAT 31 JUL 76 AS BASE DAY.

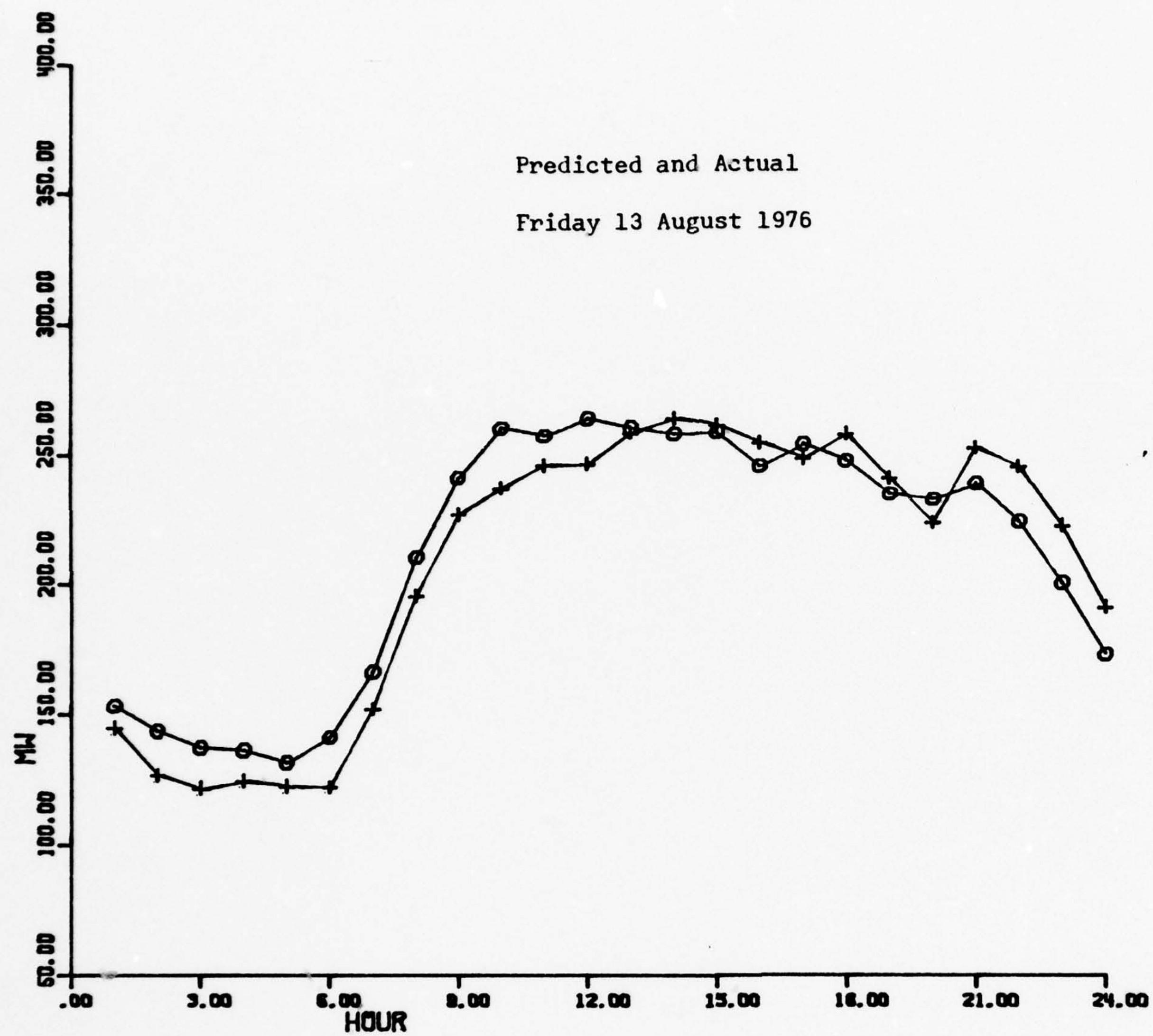
GAIN BASED ON SUN 1 AUG 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
146.9000	151.2000	-4.3000	2.84
130.1000	143.9000	-13.8000	9.59
122.9000	134.3000	-11.4000	8.49
118.1000	131.9000	-13.8000	10.46
118.0000	126.5000	-8.5000	6.72
124.7600	139.3000	-14.5400	10.44
132.9000	141.5000	-8.6000	6.08
149.7000	161.4000	-11.7000	7.25
182.5000	200.4000	-17.9000	8.93
195.2000	212.3000	-17.1000	8.05
198.7000	210.9000	-12.2000	5.78
197.2750	222.4000	-25.1250	11.30
182.8000	211.9000	-29.1000	13.73
181.2857	206.5000	-25.2143	12.21
189.8000	204.2000	-14.4000	7.05
192.0000	204.1000	-12.1000	5.93
193.2000	213.9000	-20.7000	9.68
203.4000	215.2000	-11.8000	5.48
202.2000	196.6000	5.6000	2.85
211.7000	198.7000	13.0000	6.54
189.0667	204.9000	-15.8333	7.73
201.5000	183.0000	18.5000	10.11
191.2000	170.5000	20.7000	12.14
160.4000	152.8000	7.6000	4.97

AVG. OF HOURLY PERCENT ERRORS= 8.10

PERCENT ERROR FOR TOTAL DAILY POWER= 105.41


Predicted and Actual
Friday 13 August 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTIØN FØR FRI 13 AUG 76 ****

PREDICTIØN USES THUR 12 AUG 76 AS BASE DAY.

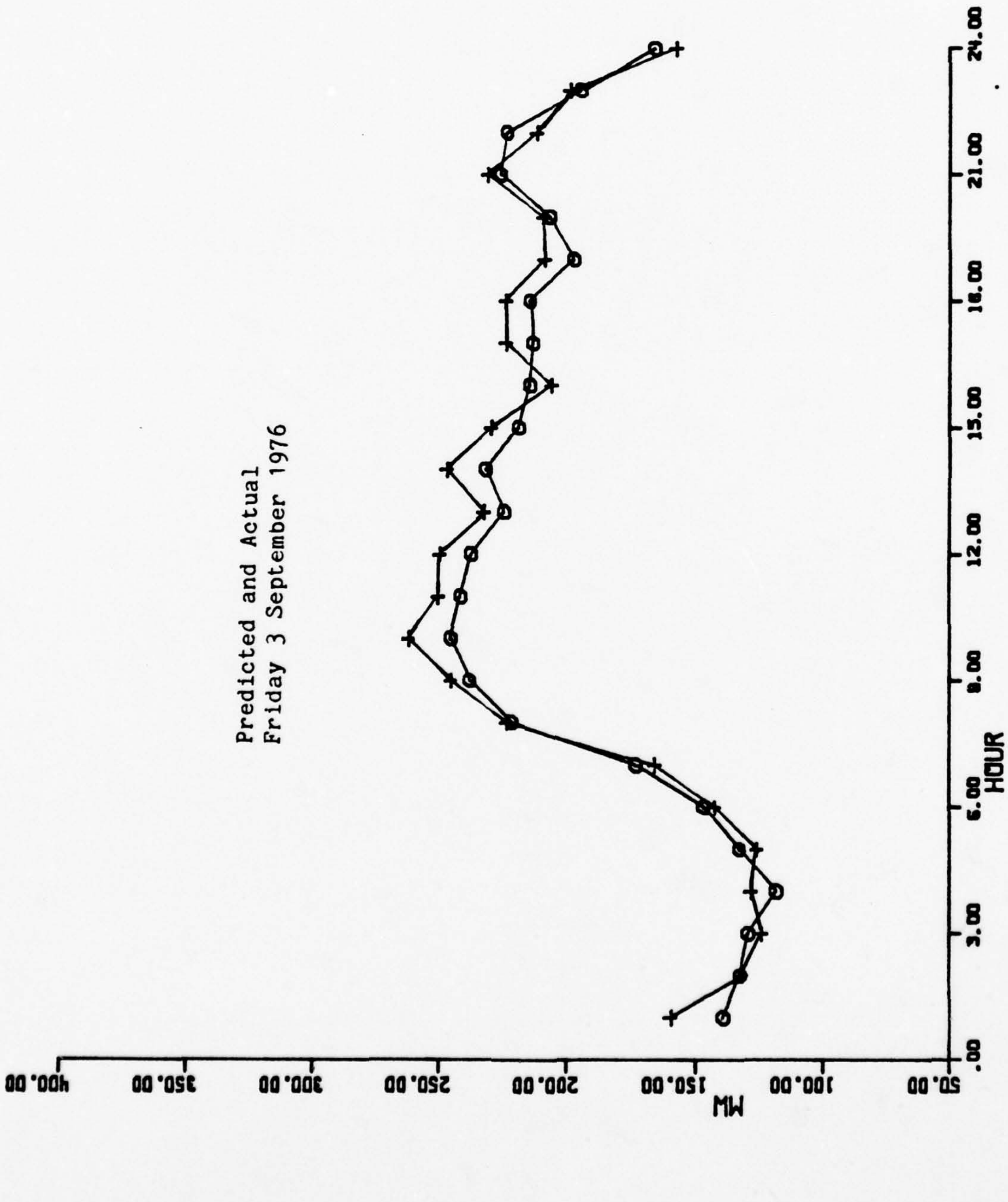
GAIN BASED ØN WED 11 AUG 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
144.6000	153.1000	-8.5000	5.55
126.5667	143.4000	-16.8333	11.74
121.6000	137.0000	-15.4000	11.24
124.5000	136.1000	-11.6000	8.52
122.4000	131.4000	-9.0000	6.85
122.0000	141.0000	-19.0000	13.48
152.0000	166.0000	-14.0000	8.43
195.4000	210.2000	-14.8000	7.04
226.8666	240.7000	-13.8334	5.75
237.0000	259.8999	-22.8999	8.81
245.9000	256.8999	-10.9999	4.28
246.4428	263.6001	-17.1573	6.51
258.3569	260.2000	-1.8430	.71
263.8000	257.8000	6.0000	2.33
260.8999	258.0000	2.8999	1.12
254.2000	245.1000	9.1000	3.71
248.3000	253.7000	-5.4000	2.13
257.7998	247.2000	10.5998	4.29
240.5000	234.2000	6.3000	2.69
223.2500	232.3000	-9.0500	3.90
252.2750	238.5000	13.7750	5.78
245.0000	223.7000	21.3000	9.52
222.1000	200.0000	22.1000	11.05
190.8000	172.5000	18.3000	10.61

AVG. ØF HØURLY PERCENT ERRØRS= 6.50

PERCENT ERRØR FØR TØTAL DAILY PØWER= 101.60


Predicted and Actual
Friday 3 September 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTIØN FØR FRI 3 SEP 76 ****

PREDICTIØN USES THUR 2 SEP 76 AS BASE DAY.

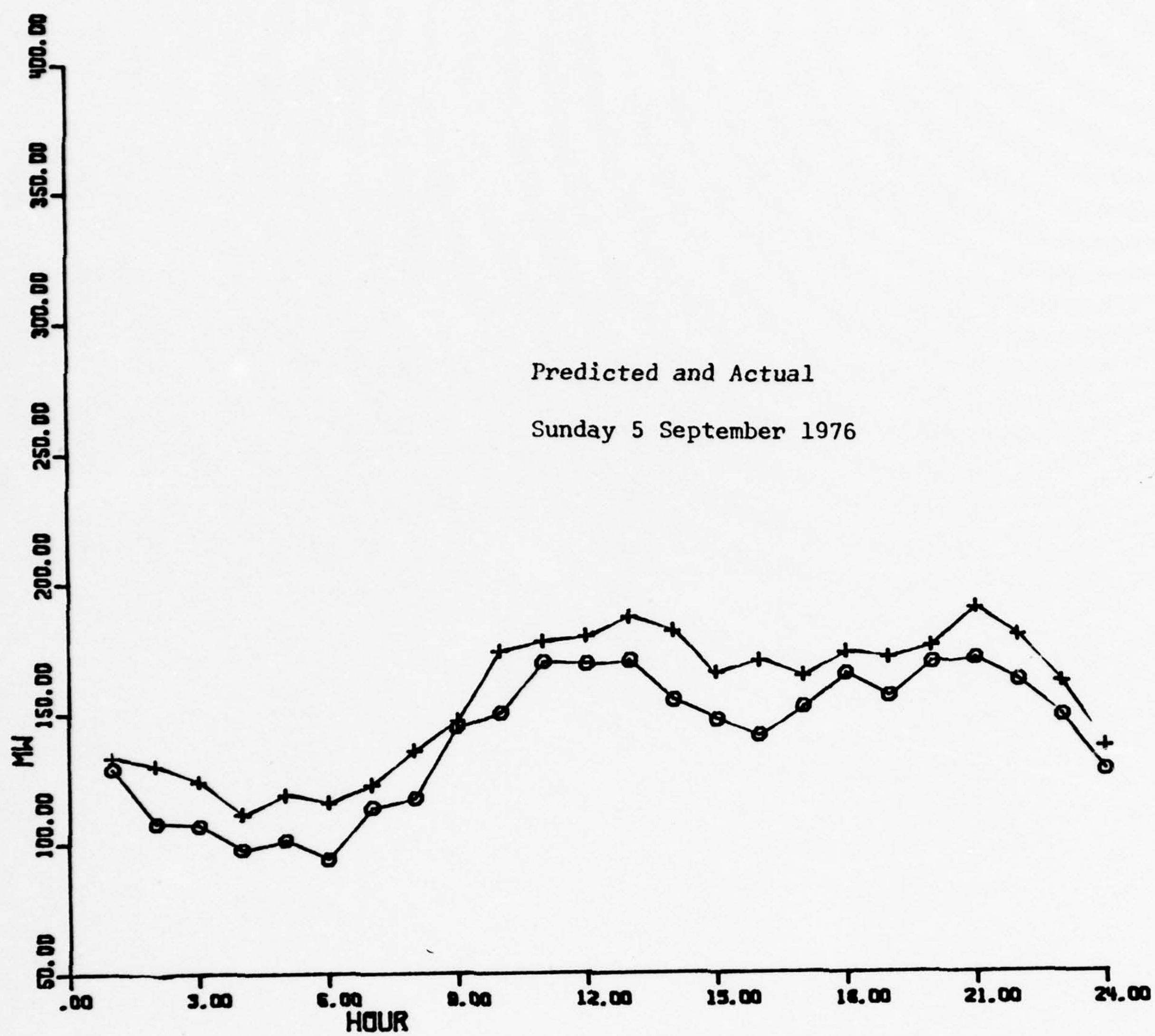
GAIN BASED ØN WED 1 SEP 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
159.2875	138.8000	20.4875	14.76
131.7250	132.2000	-.4750	.36
123.8833	129.0000	-5.1167	3.97
128.1000	118.0000	10.1000	8.56
125.8000	132.7000	-6.9000	5.20
142.3500	146.4000	-4.0500	2.77
165.6000	172.6000	-7.0000	4.06
223.1000	220.8000	2.3000	1.04
244.9667	237.4000	7.5667	3.19
261.5635	244.9000	16.6635	6.80
249.8647	240.9000	8.9647	3.72
249.2000	236.8000	12.4000	5.24
231.9556	223.9000	8.0556	3.60
246.5000	231.2000	15.3000	6.62
229.1000	218.1000	11.0000	5.04
205.5000	213.9000	-8.4000	3.93
223.3667	212.8000	10.5667	4.97
223.4000	214.0000	9.4000	4.39
208.5000	196.9000	11.6000	5.89
208.9000	206.3000	2.6000	1.26
230.5000	225.5000	5.0000	2.22
211.4000	223.0000	-11.6000	5.20
198.4615	194.3000	4.1615	2.14
157.3286	165.4000	-8.0714	4.88

AVG. ØF HØURLY PERCENT ERRØRS= 4.57

PERCENT ERRØR FØR TØTAL DAILY PØWER= 97.81


Predicted and Actual
Sunday 5 September 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR SUN 5 SEP 76 ****

PREDICTION USES SUN 29 AUG 76 AS BASE DAY.

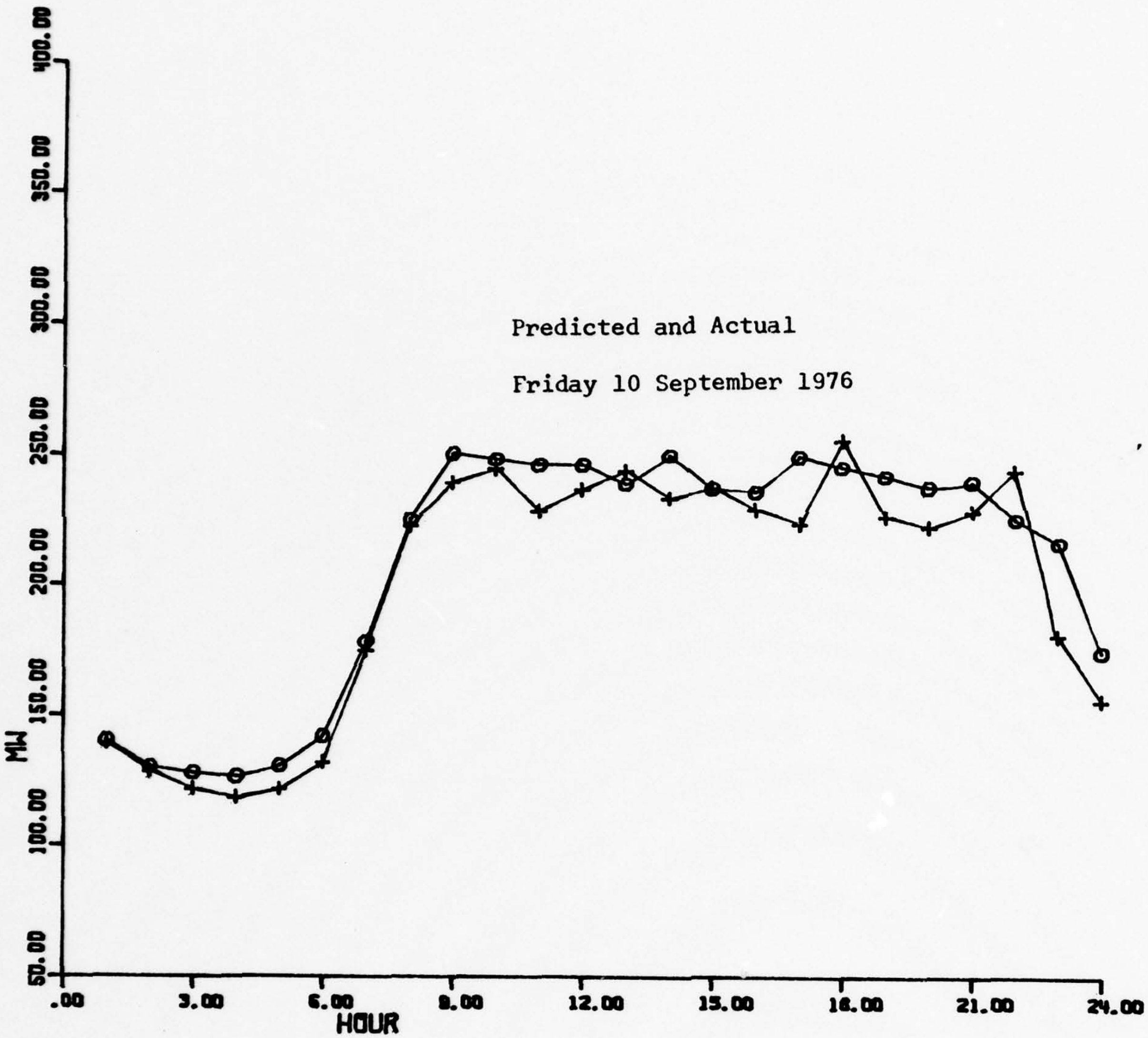
GAIN BASED ON SAT 28 AUG 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
132.9000	128.4000	4.5000	3.50
129.9000	107.5000	22.4000	20.84
123.7500	106.6000	17.1500	16.09
111.1000	97.4000	13.7000	14.07
118.6500	101.0000	17.6500	17.48
115.4000	93.6000	21.8000	23.29
122.4000	113.5000	8.9000	7.84
135.5000	116.8000	18.7000	16.01
147.1000	144.5000	2.6000	1.80
173.5000	149.8000	23.7000	15.82
177.1000	169.2000	7.9000	4.67
179.1000	168.3000	10.8000	6.42
186.6000	169.7000	16.9000	9.96
181.0000	154.3000	26.7000	17.30
165.0000	146.8000	18.2000	12.40
169.6000	140.8000	28.8000	20.45
163.8000	151.8000	12.0000	7.91
172.8000	164.5000	8.3000	5.05
170.6000	155.8000	14.8000	9.50
174.9000	168.5000	6.4000	3.80
189.7000	170.1000	19.6000	11.52
178.9000	161.7000	17.2000	10.64
161.3000	148.3000	13.0000	8.77
136.4000	127.1000	9.3000	7.32

AVG. OF HOURLY PERCENT ERRORS= 11.35

PERCENT ERROR FOR TOTAL DAILY POWER= 90.29


Predicted and Actual
Friday 10 September 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
8.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR FRI 10 SEP 76 ****

PREDICTION USES THUR 9 SEP 76 AS BASE DAY.

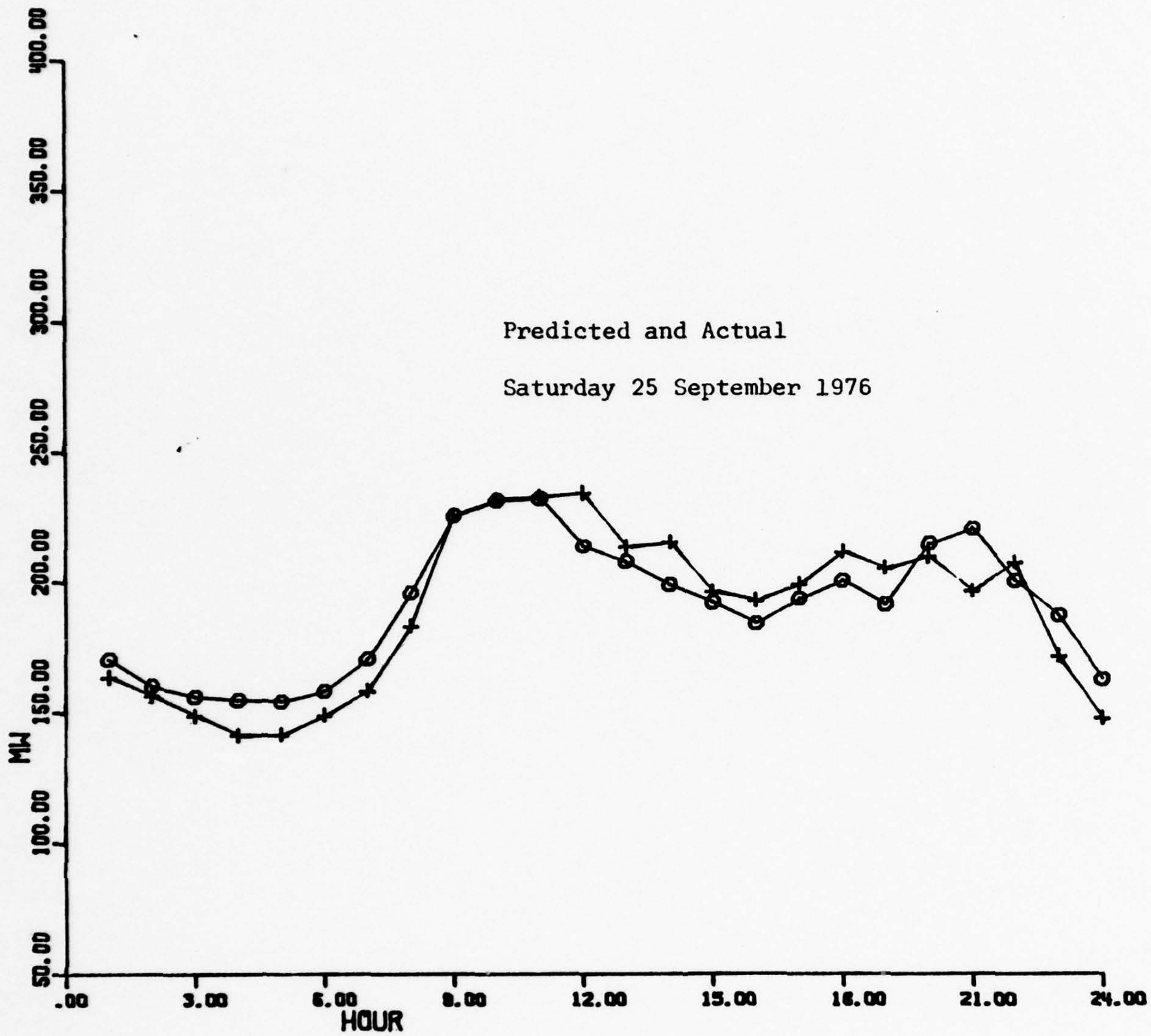
GAIN BASED ON WED 8 SEP 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
139.0000	139.9000	-.9000	.64
128.0000	129.8000	-1.8000	1.39
121.4000	127.5000	-6.1000	4.78
118.1000	126.0000	-7.9000	6.27
121.3000	130.2000	-8.9000	6.84
131.8000	141.6000	-9.8000	6.92
174.4600	177.8000	-3.3400	1.88
222.7000	224.9000	-2.2000	.98
239.0500	250.0000	-10.9500	4.38
244.5000	247.9000	-3.4000	1.37
228.1000	245.9000	-17.8000	7.24
236.4250	245.9000	-9.4750	3.85
243.7000	238.6000	5.1000	2.14
233.3000	249.6000	-16.3000	6.53
237.3000	236.8000	.5000	.21
228.9000	235.5000	-6.6000	2.80
223.7000	249.1000	-25.4000	10.20
255.4000	245.0000	10.4000	4.24
226.2143	241.6000	-15.3857	6.37
222.2000	237.3000	-15.1000	6.36
228.4000	239.5000	-11.1000	4.63
243.8000	225.0000	18.8000	8.36
180.5000	216.0000	-35.5000	16.44
155.8000	174.1000	-18.3000	10.51

AVG. OF HOURLY PERCENT ERRORS= 5.22

PERCENT ERROR FOR TOTAL DAILY POWER= 104.00


Predicted and Actual
Saturday 25 September 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR SAT 25 SEP 76 ****

PREDICTION USES SAT 18 SEP 76 AS BASE DAY.

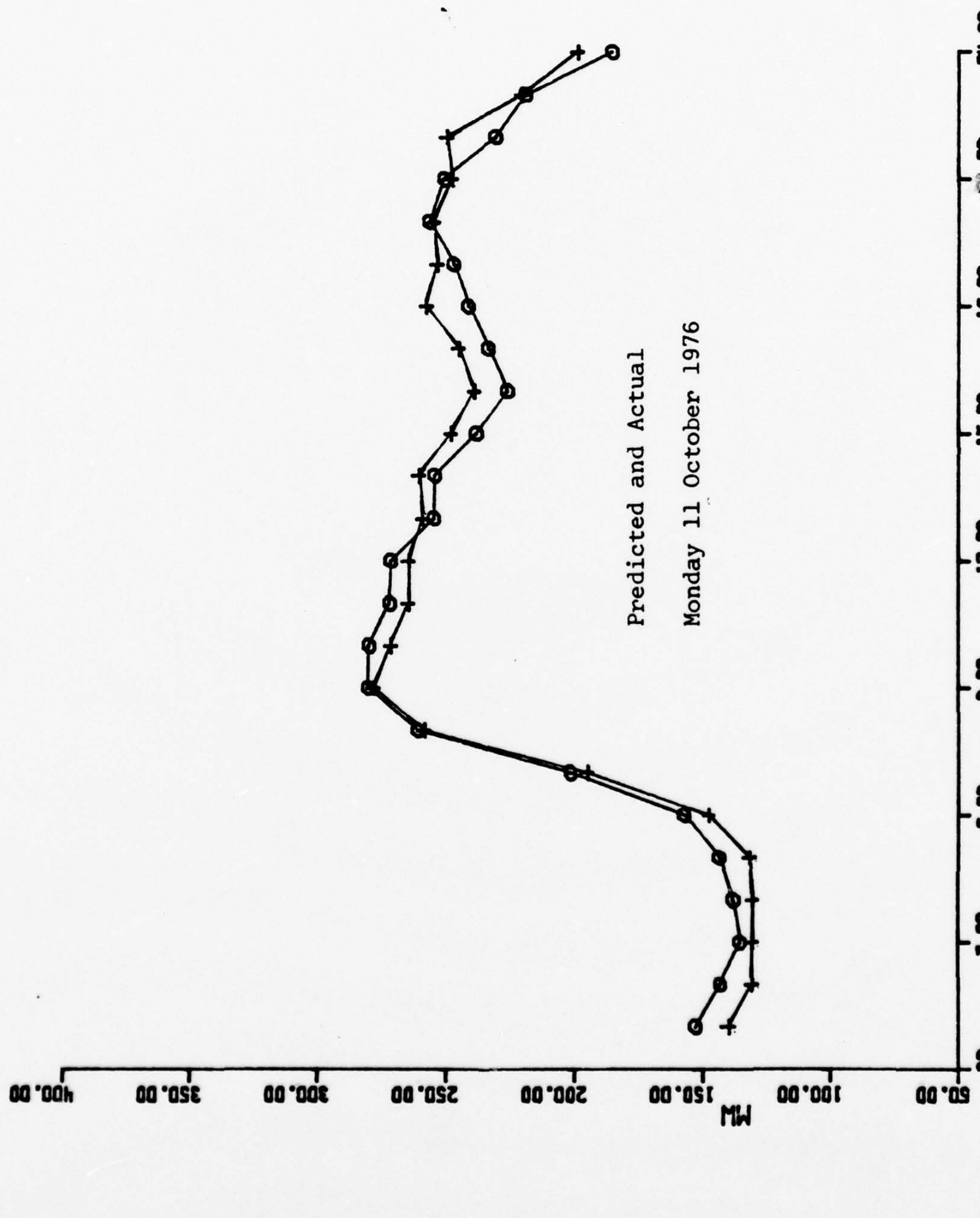
GAIN BASED ON SUN 19 SEP 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
163.4000	170.1000	-6.7000	3.94
156.3000	159.9000	-3.6000	2.25
148.5000	155.8000	-7.3000	4.69
141.2000	154.5000	-13.3000	8.61
141.4000	153.9000	-12.5000	8.12
148.7000	157.9000	-9.2000	5.83
158.2000	170.1000	-11.9000	7.00
182.8000	195.5000	-12.7000	6.50
225.4000	225.1000	.3000	.13
231.5000	231.0000	.5000	.22
232.6000	231.7000	.9000	.39
233.9000	213.3000	20.6000	9.66
213.2000	207.5000	5.7000	2.75
214.9000	198.4000	16.5000	8.32
195.9000	191.7000	4.2000	2.19
192.4000	183.4000	9.0000	4.91
198.7000	193.0000	5.7000	2.95
211.1000	199.8000	11.3000	5.66
204.8000	190.7000	14.1000	7.39
209.1750	214.1000	-4.9250	2.30
195.9000	219.9000	-24.0000	10.91
206.9000	199.8000	7.1000	3.55
171.1000	186.6000	-15.5000	8.31
147.5000	162.2000	-14.7000	9.06

AVG. OF HOURLY PERCENT ERRORS= 5.23

PERCENT ERROR FOR TOTAL DAILY POWER= 100.89


Predicted and Actual
Monday 11 October 1976
MW
60.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR MON 11 OCT 76 ****

PREDICTION USES MON 4 OCT 76 AS BASE DAY.

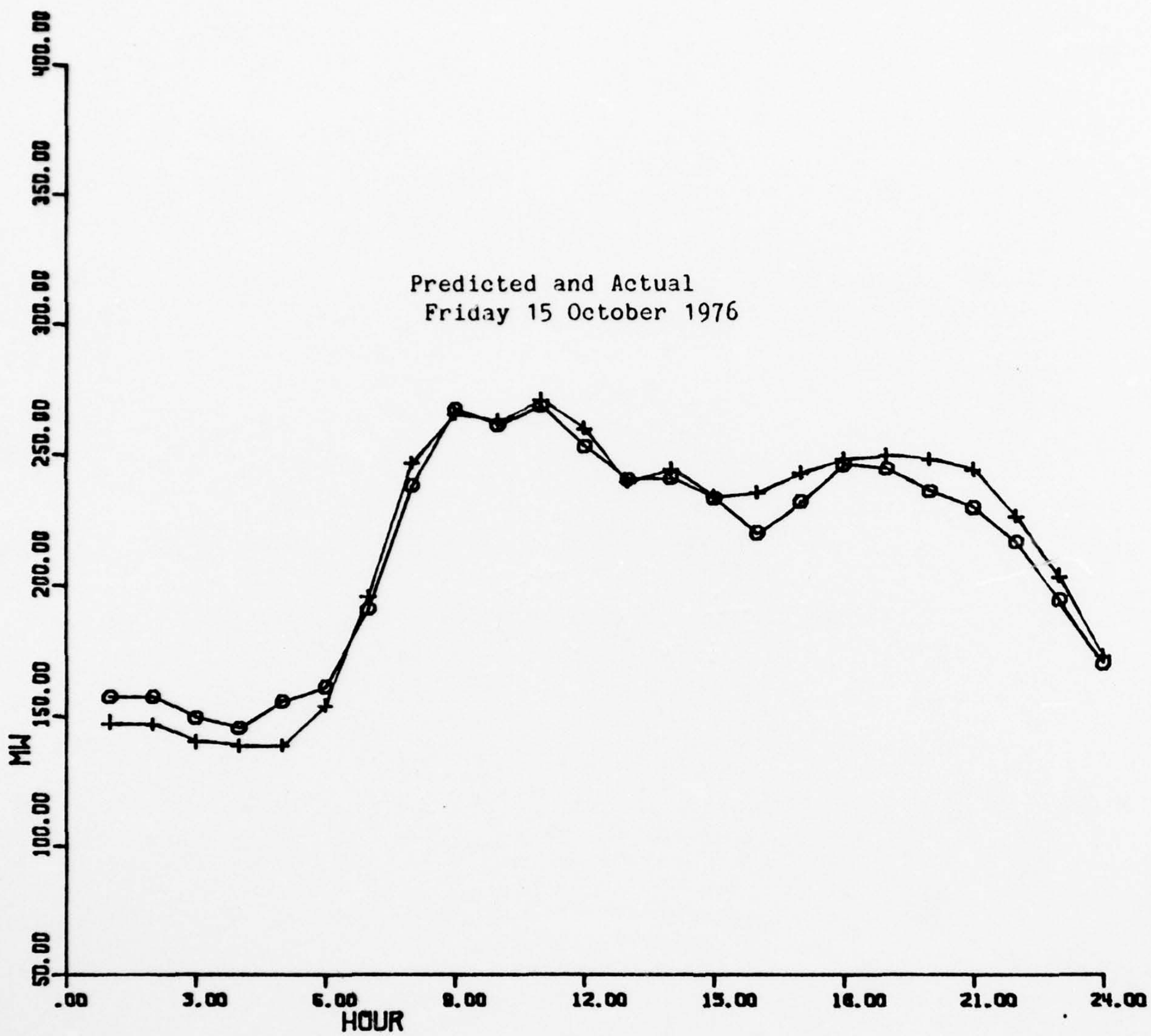
GAIN BASED ON FRI 8 OCT 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
139.7000	152.7000	-13.0000	8.51
130.7000	143.0000	-12.3000	8.60
130.3000	135.2000	-4.9000	3.62
130.3000	137.8000	-7.5000	5.44
131.7000	143.5000	-11.8000	8.22
147.6000	157.1000	-9.5000	6.05
194.7000	201.3000	-6.6000	3.28
257.8999	260.6001	-2.7002	1.04
277.7000	279.6001	-1.9001	.68
270.8999	279.2000	-8.3000	2.97
264.0200	271.1001	-7.0801	2.61
264.0664	270.7000	-6.6335	2.45
258.5598	254.1000	4.4598	1.76
260.0398	253.8000	6.2398	2.46
247.6765	237.6000	10.0765	4.24
238.6000	225.6000	13.0000	5.76
244.7920	233.0000	11.7920	5.06
257.2000	240.7000	16.5000	6.85
252.9833	246.4000	6.5833	2.67
254.2429	255.8000	-1.5571	.61
246.9000	249.8000	-2.9000	1.16
248.9666	230.0000	18.9666	8.25
220.2000	218.5000	1.7000	.78
198.4000	184.8000	13.6000	7.36

AVG. OF HOURLY PERCENT ERRORS= 4.18

PERCENT ERROR FOR TOTAL DAILY POWER= 99.88


Predicted and Actual
Friday 15 October 1976
MW
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350.00
300.00
250.00
200.00
150.00
100.00
50.00
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3.00
6.00
8.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR FRI 15 OCT 76 ****

PREDICTION USES THUR 14 OCT 76 AS BASE DAY.

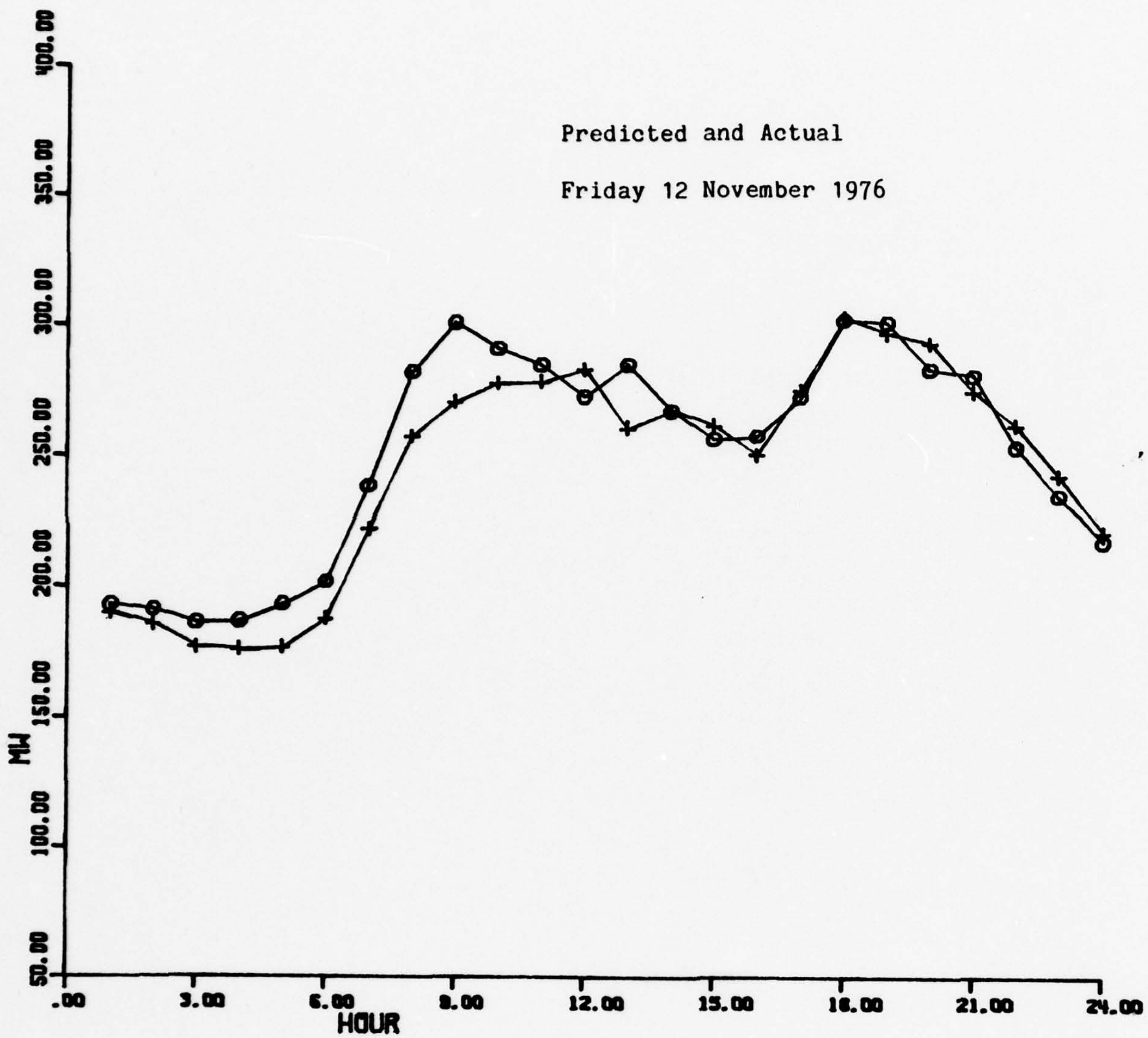
GAIN BASED ON WED 13 OCT 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
147.0875	157.2000	-10.1125	6.43
146.6286	157.1000	-10.4714	6.67
139.7384	148.9000	-9.1615	6.15
138.2714	144.9000	-6.6286	4.57
138.3428	155.1000	-16.7572	10.80
153.8538	160.7000	-6.8462	4.26
195.2400	190.3000	4.9400	2.60
246.2222	237.5000	8.7222	3.67
265.0498	266.6001	-1.5503	.58
262.3000	260.8999	1.4001	.54
270.3398	267.8999	2.4399	.91
259.3535	252.6000	6.7535	2.67
238.9000	239.8000	-.9000	.38
243.7000	240.4000	3.3000	1.37
233.4000	232.5000	.9000	.39
234.9818	219.2000	15.7818	7.20
242.5182	231.4000	11.1182	4.80
247.8999	245.6000	2.2999	.94
249.0182	244.0000	5.0182	2.06
247.7000	235.2000	12.5000	5.31
243.6000	229.0000	14.6000	6.38
225.7000	215.7000	10.0000	4.64
202.9000	193.7000	9.2000	4.75
172.5000	169.6000	2.9000	1.71

AVG. OF HOURLY PERCENT ERRORS= 3.74

PERCENT ERROR FOR TOTAL DAILY POWER= 99.04


Predicted and Actual
Friday 12 November 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR

BEST AVAILABLE COPY

PREDICTION FOR FRI 12 NOV 76 ****

PREDICTION USES THUR 11 NOV 76 AS BASE DAY.

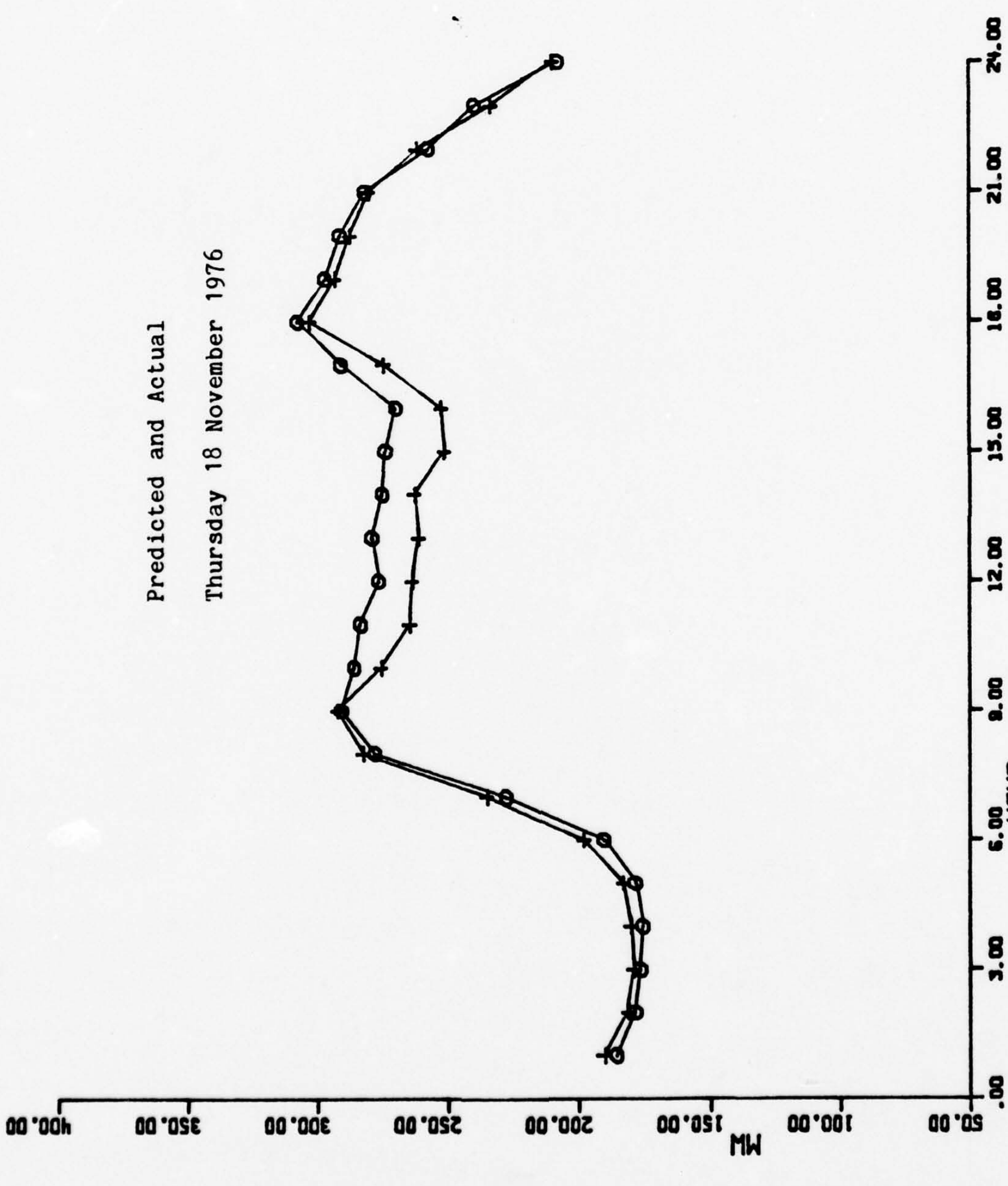
GAIN BASED ON WED 10 NOV 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
189.5000	192.6000	-3.1000	1.61
185.1000	190.8000	-5.7000	2.99
176.6000	185.8000	-9.2000	4.95
175.8000	186.3000	-10.5000	5.64
176.5000	192.8000	-16.3000	8.45
187.5000	201.3000	-13.8000	6.86
221.5000	237.9000	-16.4000	6.89
257.0000	281.3000	-24.3000	8.64
270.0000	300.2000	-30.2000	10.06
277.2000	290.3999	-13.2000	4.55
277.8000	284.0000	-6.2000	2.18
282.5000	272.0000	10.5000	3.86
260.2000	284.2000	-24.0000	8.44
267.0000	266.5000	.5000	.19
261.0000	255.7000	5.3000	2.07
249.8000	257.0000	-7.2000	2.80
274.5249	271.6001	2.9248	1.08
302.1748	301.3000	.8748	.29
296.1199	300.2000	-4.0801	1.36
292.5000	282.3999	10.1001	3.58
273.7908	279.8000	-6.0093	2.15
261.1250	252.7000	8.4250	3.33
241.8706	234.0000	7.8706	3.36
220.2389	216.6000	3.6389	1.68

AVG. OF HOURLY PERCENT ERRORS= 4.04

PERCENT ERROR FOR TOTAL DAILY POWER= 102.38


Predicted and Actual
Thursday 18 November 1976
MW
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR THUR 18 NOV 76 ****

PREDICTION USES WED 17 NOV 76 AS BASE DAY.

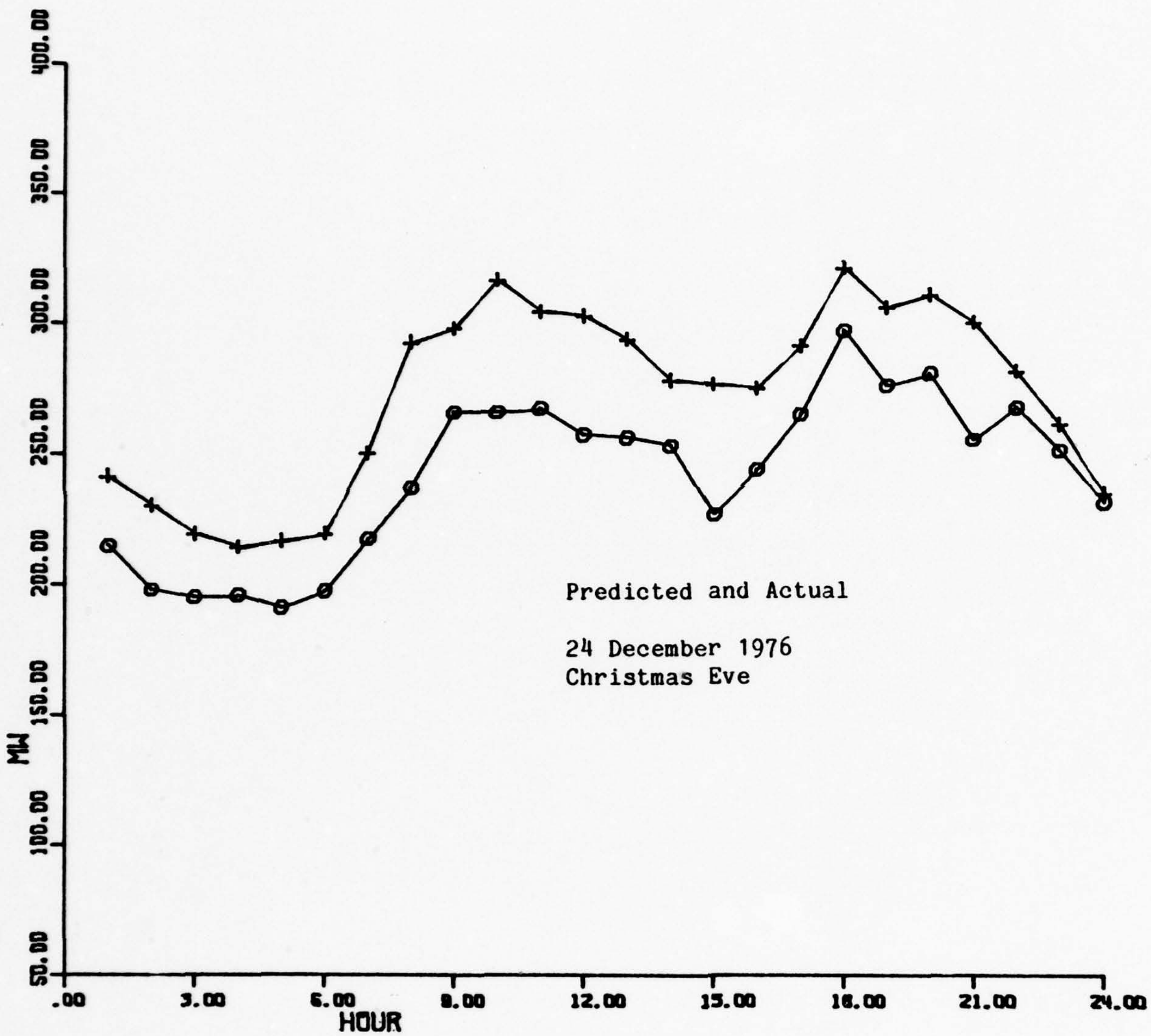
GAIN BASED ON TUE 16 NOV 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
190.2000	185.4000	4.8000	2.59
181.3000	178.3000	3.0000	1.68
179.2000	176.3000	2.9000	1.64
180.0000	175.5000	4.5000	2.56
182.9000	178.2000	4.7000	2.64
197.9500	190.2000	7.7500	4.07
234.8500	227.2000	7.6500	3.37
281.9250	277.3999	4.5251	1.63
291.8000	290.2000	1.6001	.55
275.1001	285.3000	-10.2000	3.58
263.8999	282.7000	-18.8000	6.65
263.0000	275.8000	-12.8000	4.64
260.5000	278.3000	-17.8000	6.40
262.1001	274.3000	-12.2000	4.45
250.6000	272.8999	-22.2999	8.17
251.8000	269.1001	-17.3001	6.43
273.8999	290.0000	-16.1001	5.55
302.0498	306.8000	-4.7502	1.55
292.3000	296.0000	-3.7000	1.25
286.5000	290.2000	-3.7000	1.27
279.3999	280.8000	-1.4001	.50
261.0000	256.6001	4.3999	1.71
232.7000	238.8000	-6.1000	2.55
209.1571	207.1000	2.0571	.99

AVG. OF HOURLY PERCENT ERRORS= 3.18

PERCENT ERROR FOR TOTAL DAILY POWER= 101.69


Predicted and Actual
24 December 1976
Christmas Eve
MW
HOUR
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR FRI 24 DEC 76 H ****

PREDICTION USES THUR 23 DEC 76 AS BASE DAY.

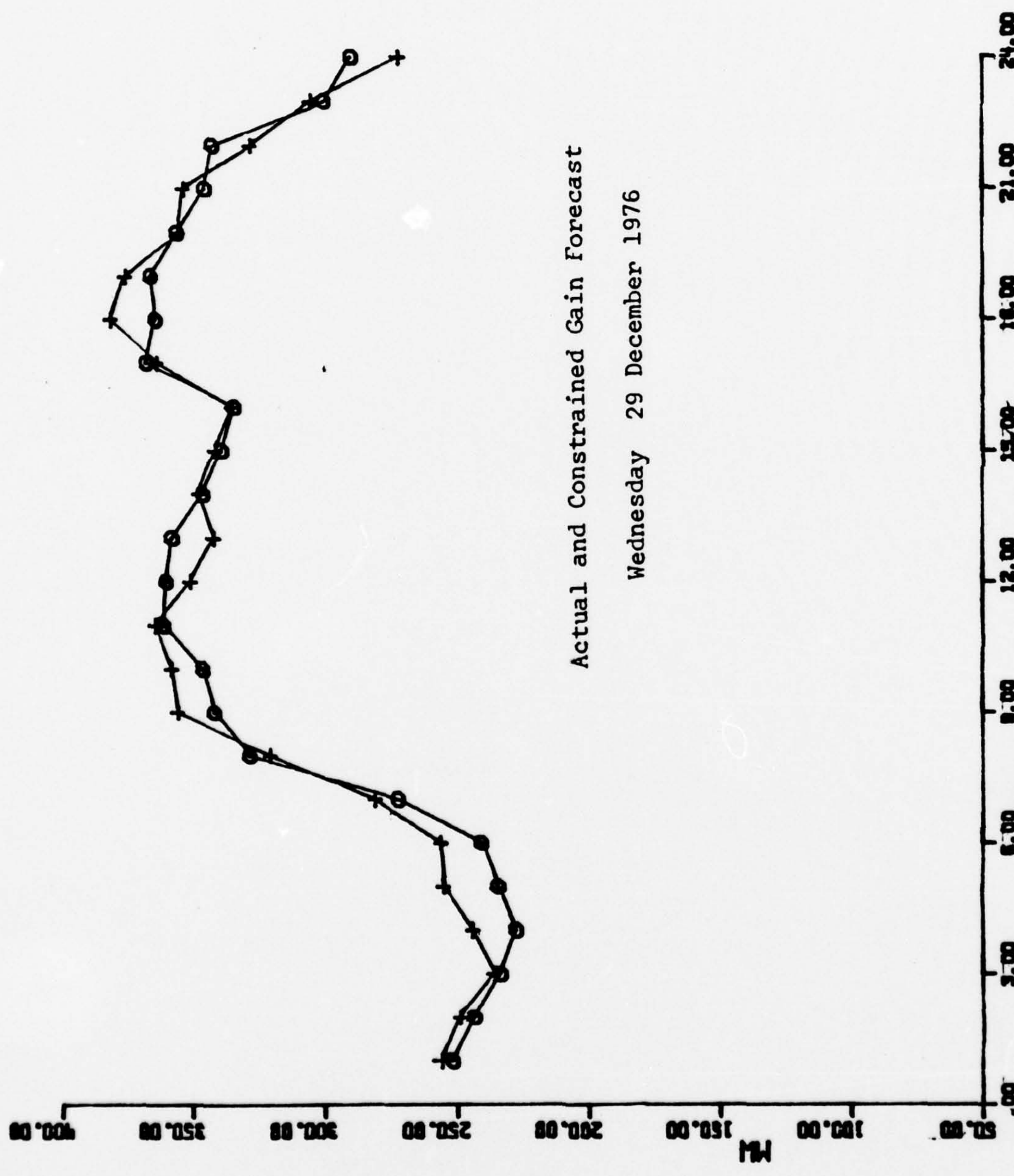
GAIN BASED ON WED 22 DEC 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
241.2000	214.5000	26.7000	12.45
230.0000	197.6000	32.4000	16.40
219.0000	194.7000	24.3000	12.48
214.0000	195.4000	18.6000	9.52
216.3000	190.7000	25.6000	13.42
219.1000	197.0000	22.1000	11.22
249.8000	217.0000	32.8000	15.12
292.2000	236.5000	55.7000	23.55
297.5000	265.2000	32.3000	12.18
316.0000	265.3000	50.7000	19.11
303.8000	266.8000	37.0000	13.87
302.2000	256.6001	45.5999	17.77
293.3999	255.6000	37.7999	14.79
277.6001	252.6000	25.0001	9.90
276.0000	226.2000	49.8000	22.02
274.5000	243.4000	31.1000	12.78
290.8999	264.5000	26.3999	9.98
320.7090	296.3999	24.3091	8.20
305.3999	275.3999	30.0000	10.89
310.3000	280.0000	30.3000	10.82
299.7000	255.0000	44.7000	17.53
281.1001	267.1001	14.0000	5.24
261.0000	250.9000	10.1000	4.03
234.6000	231.0000	3.6000	1.56

AVG. OF HOURLY PERCENT ERRORS= 12.70

PERCENT ERROR FOR TOTAL DAILY POWER= 88.80


Actual and Constrained Gain Forecast
Wednesday 29 December 1976
MW
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

BEST AVAILABLE COPY

PREDICTION FOR WED 29 DEC 76 ****

PREDICTION USES TUE 28 DEC 76 AS BASE DAY.

GAIN BASED ON MON 27 DEC 76

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
255.8000	251.3000	4.5000	1.79
248.6001	242.8000	5.8001	2.39
235.8000	233.2000	2.6000	1.11
243.8000	227.2000	16.6001	7.31
254.8000	233.9000	20.9001	8.94
255.8999	240.3000	15.5999	6.49
280.8999	271.8000	9.0999	3.35
320.1001	327.7000	-7.5999	2.32
355.3000	341.0000	14.3000	4.19
357.3999	345.3999	12.0000	3.47
363.8000	360.1001	3.7000	1.03
350.3000	359.2000	-8.8999	2.48
341.3000	356.8999	-15.5999	4.37
346.8000	345.2000	1.6001	.46
340.8999	338.1001	2.7998	.83
334.3000	333.3999	.9001	.27
362.8000	366.8000	-4.0000	1.09
380.3000	363.0000	17.3000	4.77
375.1001	365.0000	10.1001	2.77
354.5403	355.0000	-.4597	.13
352.6997	344.2000	8.4998	2.47
327.0000	341.2000	-14.2000	4.16
304.1665	299.0000	5.1665	1.73
271.2612	288.8000	-17.5388	6.07

AVG. OF HOURLY PERCENT ERRORS= 3.08

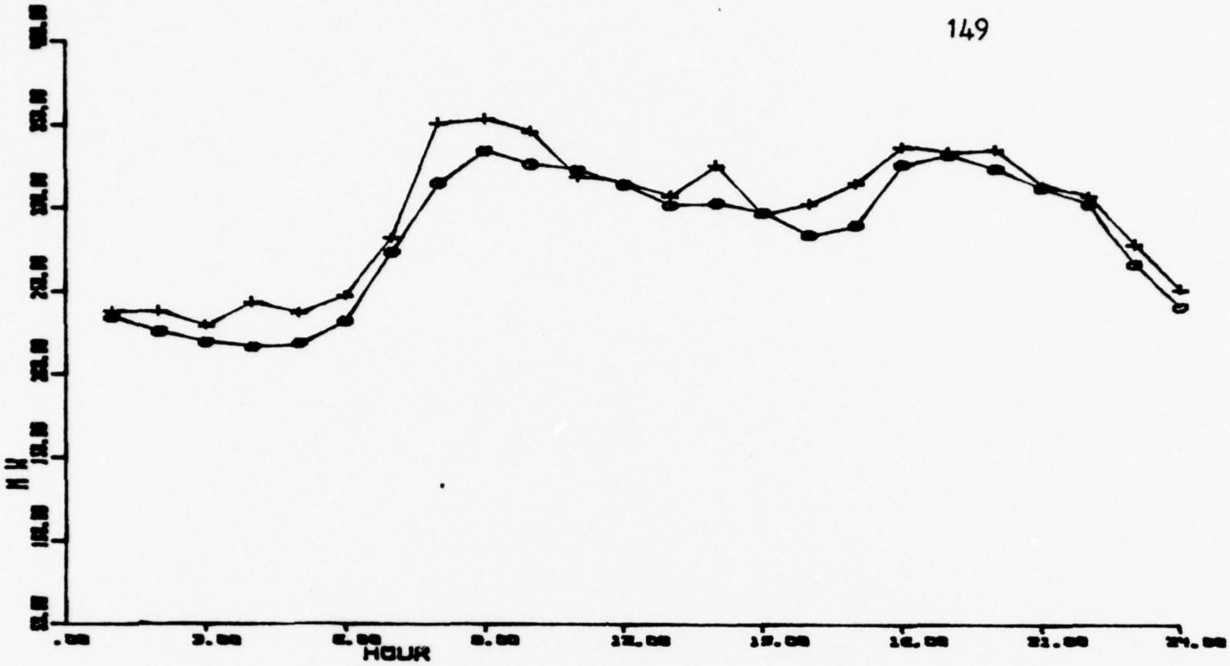
PERCENT ERROR FOR TOTAL DAILY POWER= 98.91

APPENDIX 4

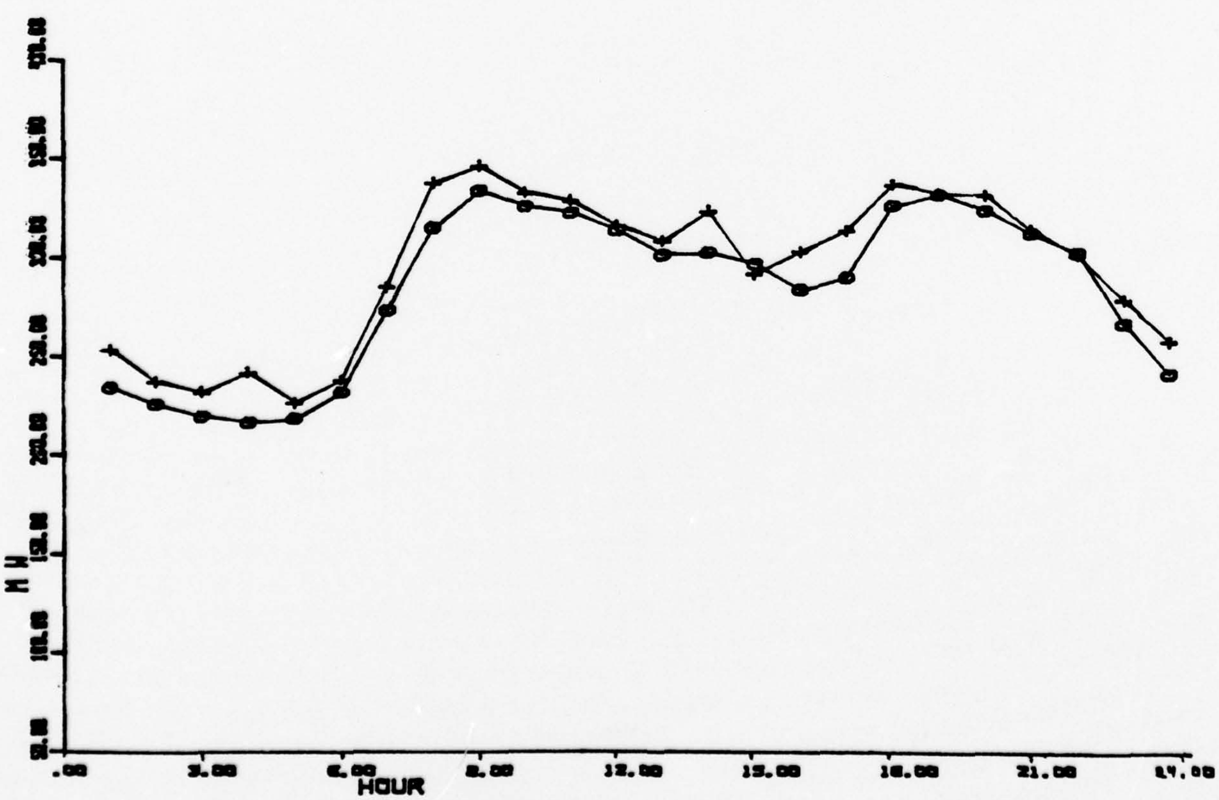
FORECASTING COMPARISONS

Comparison forecasts are made with the hybird model and the constrained gain method for selected days.

Affects of temperature forecast errors on the load forecast are shown.



SPSS Prediction 20 Jan. 1977



Constrained Gain Prediction 20 Jan. 1977

BEST AVAILABLE COPY

PREDICTION FOR THUR 20 JAN 77 ****

PREDICTION USES WED 19 JAN 77 AS BASE DAY.

GAIN BASED ON TUE 18 JAN 77

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
253.0126	233.9000	19.1126	8.17
236.9626	225.3000	11.6626	5.18
231.7500	219.1000	12.6500	5.77
241.8445	216.3000	25.5445	11.81
226.5001	218.4000	8.1001	3.71
238.0000	231.7000	6.3000	2.72
285.0000	273.0000	12.0000	4.40
337.7000	314.8000	22.8999	7.27
346.5000	333.7000	12.8000	3.84
332.7000	325.6001	7.0999	2.18
328.7000	322.3999	6.3000	1.95
316.1001	313.7000	2.4001	.77
308.5000	301.3999	7.1001	2.36
323.6001	302.7000	20.9001	6.90
291.7000	297.0000	-5.3000	1.78
303.3000	283.8000	19.5000	6.87
313.8000	289.8999	23.9001	8.24
337.2000	326.3999	10.8000	3.31
332.6001	332.0000	.6001	.18
331.6001	323.8000	7.8000	2.41
313.8999	312.2000	1.7000	.54
301.2000	302.5000	-1.3000	.43
278.7000	266.6001	12.0999	4.54
257.6453	241.0000	16.6453	6.91

AVG. OF HOURLY PERCENT ERRORS= 4.26

PERCENT ERROR FOR TOTAL DAILY POWER= 96.30

BEST AVAILABLE COPY

PREDICTION FOR THUR 20 JAN 77 ****

PREDICTION USES WED 19 JAN 77 AS BASE DAY.

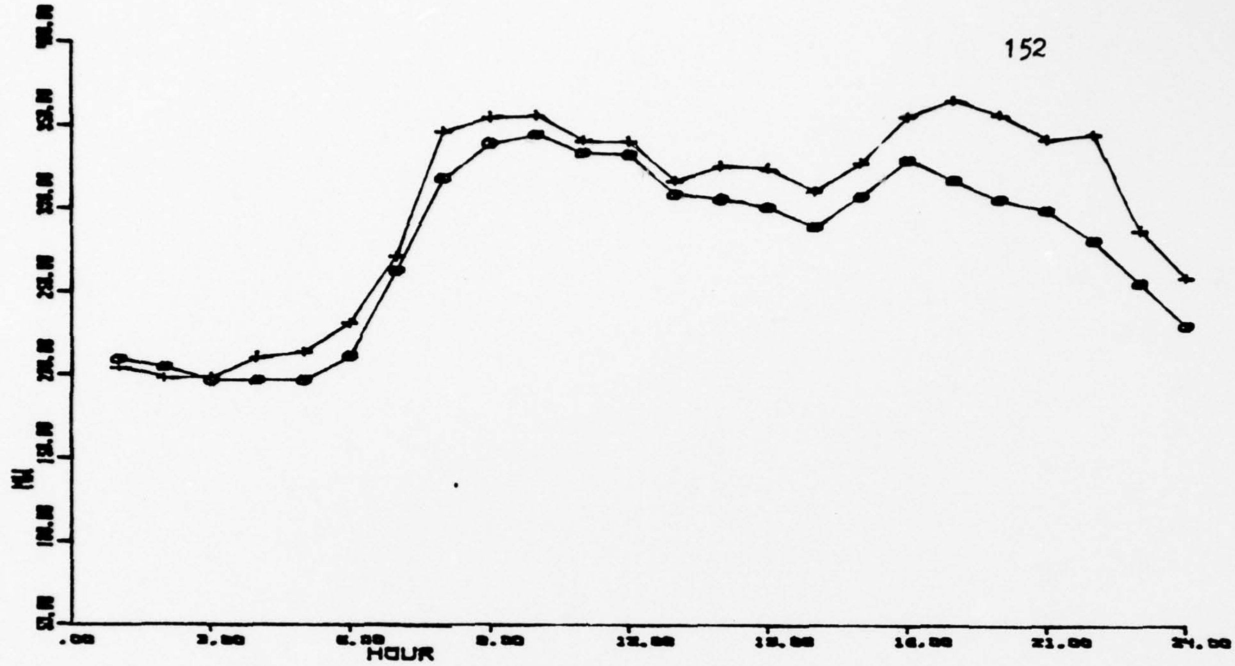
GAIN BASED ON TUE 18 JAN 77

GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

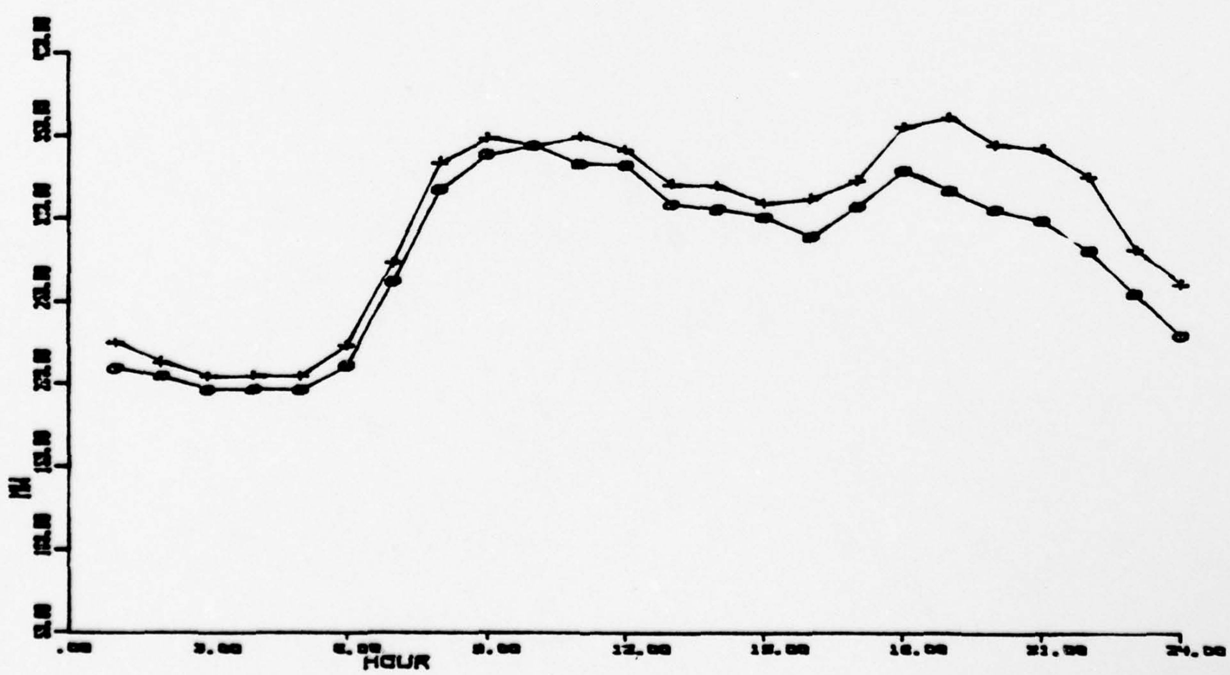
PREDICTION	ACTUAL MW	DIFFERENCE	%
237.5000	233.9000	3.6000	1.54
237.7870	225.3000	12.4870	5.54
229.3700	219.1000	10.2700	4.69
243.2800	216.3000	26.9800	12.47
236.4920	218.4000	18.0920	8.28
246.9420	231.7000	15.2420	6.58
281.9399	273.0000	8.9399	3.27
351.1299	314.8000	36.3298	11.54
352.9600	333.7000	19.2600	5.77
345.6199	325.6001	20.0198	6.15
318.4998	322.3999	-3.9001	1.21
314.7400	313.7000	1.0400	.33
307.2200	301.3999	5.8201	1.93
325.5840	302.7000	22.8840	7.56
296.5879	297.0000	-.4121	.14
302.7400	283.8000	18.9399	6.67
315.3198	289.8999	25.4199	8.77
337.0398	326.3999	10.6399	3.26
333.8799	332.0000	1.8799	.57
335.4399	323.8000	11.6399	3.59
313.6599	312.2000	1.4600	.47
307.6318	302.5000	5.1318	1.70
278.7397	266.6001	12.1396	4.55
251.7400	241.0000	10.7400	4.46

AVG. OF HOURLY PERCENT ERRORS= 4.63

PERCENT ERROR FOR TOTAL DAILY POWER= 95.85



SPSS Prediction 24 Jan. 1977



Constrained Gain Prediction 24 Jan. 1977

BEST AVAILABLE COPY

PREDICTION FOR MON 24 JAN 77 ****

PREDICTION USES MON 17 JAN 77 AS BASE DAY.

GAIN BASED ON FRI 21 JAN 77

GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
224.6333	208.9000	15.7333	7.53
212.7000	204.2000	8.5000	4.16
204.5875	196.2000	8.3875	4.27
205.2500	196.5000	8.7500	4.45
205.0000	196.4000	8.6000	4.38
223.4000	211.1000	12.3000	5.83
273.7000	262.1001	11.5999	4.43
334.1001	317.7000	16.4001	5.16
348.8000	338.8000	10.0000	2.95
344.2000	344.2000	.0000	.00
349.5000	332.8999	16.6001	4.99
341.6001	332.2000	9.4001	2.83
320.8999	308.5000	12.3999	4.02
319.8000	305.5000	14.3000	4.68
309.6001	300.8999	8.7002	2.89
312.6001	289.3000	23.3000	8.05
323.5000	307.3999	16.1001	5.24
355.8999	329.3999	26.5000	8.04
361.6001	317.1001	44.5000	14.03
345.3000	305.7000	39.6001	12.95
342.8000	299.1001	43.7000	14.61
326.0000	281.2000	44.8000	15.93
282.5171	255.5000	27.0171	10.57
261.3462	230.1000	31.2462	13.58

AVG. OF HOURLY PERCENT ERRORS= 6.90

PERCENT ERROR FOR TOTAL DAILY POWER= 93.57

PREDICTION FOR MON 24 JAN 77 ****

PREDICTION USES MON 17 JAN 77 AS BASE DAY.

GAIN BASED ON FRI 21 JAN 77

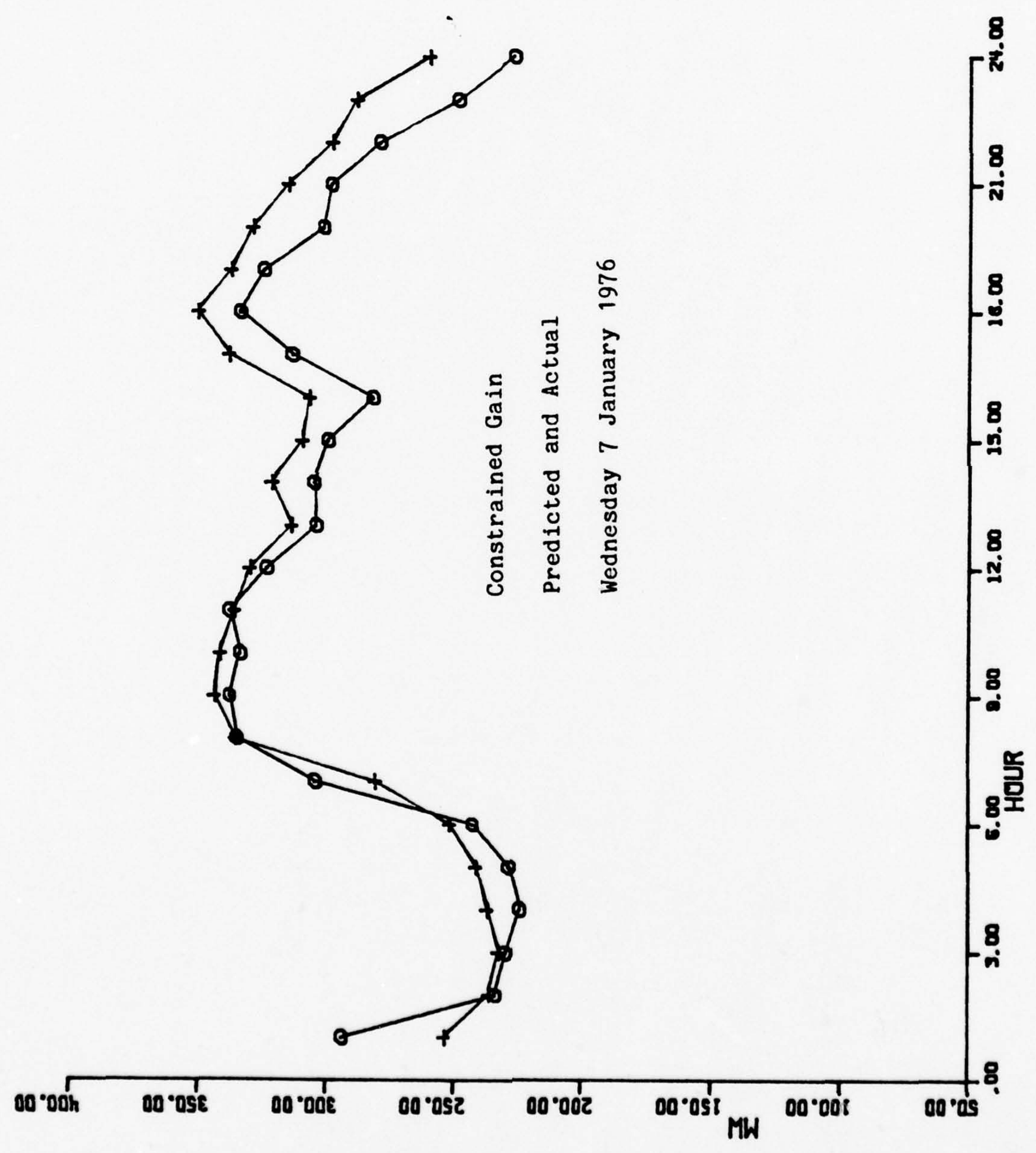
GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

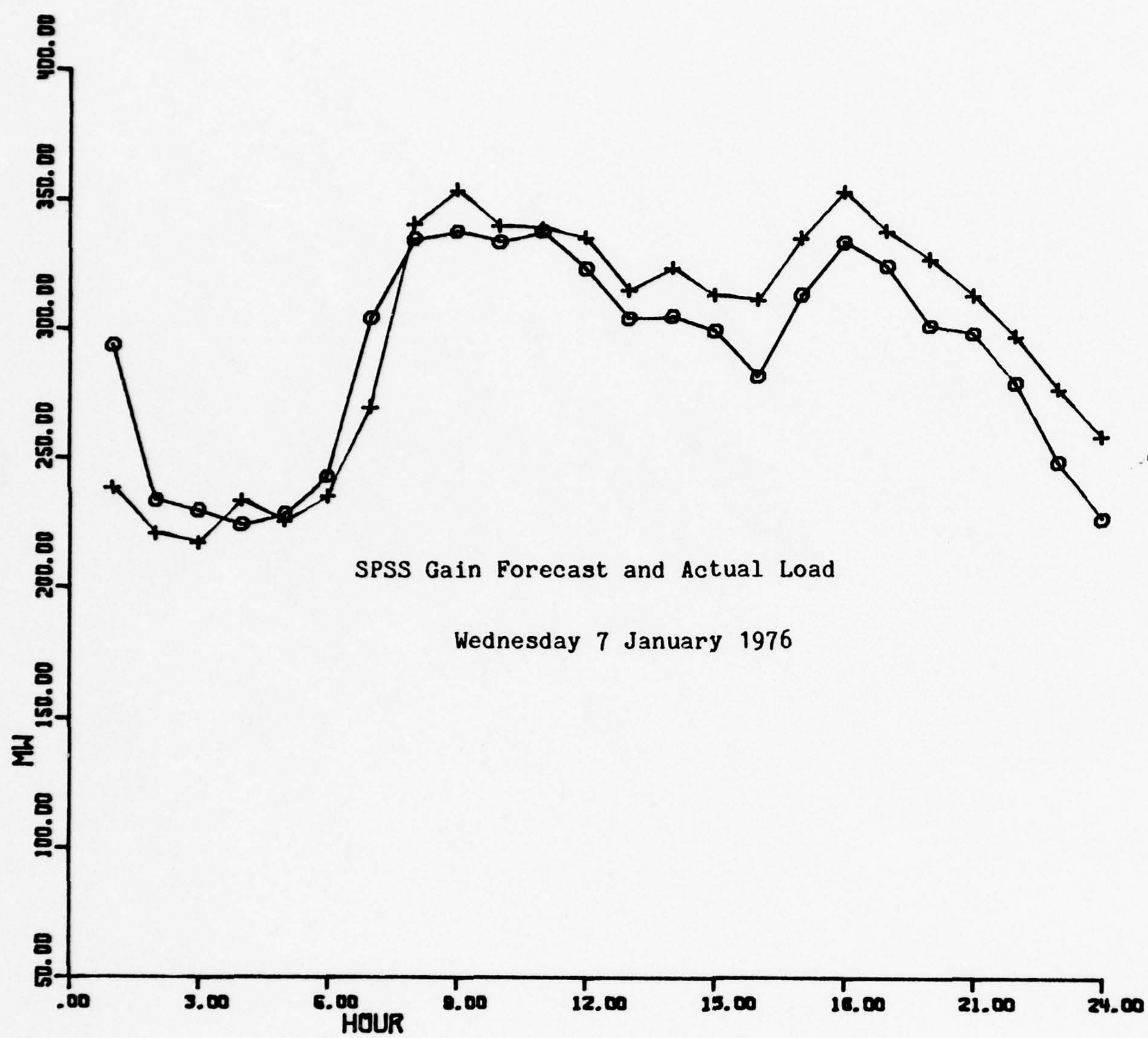
PREDICTION	ACTUAL MW	DIFFERENCE	%
204.3000	208.9000	-4.6000	2.20
197.8650	204.2000	-6.3350	3.10
198.5500	196.2000	2.3500	1.20
210.5000	196.5000	14.0000	7.12
213.6400	196.4000	17.2400	8.78
231.2900	211.1000	20.1900	9.56
270.9998	262.1001	8.8997	3.40
345.9500	317.7000	28.2500	8.89
354.5000	338.8000	15.7000	4.63
355.5999	344.2000	11.3999	3.31
340.5000	332.8999	7.6001	2.28
340.3999	332.2000	8.2000	2.47
317.0598	308.5000	8.5598	2.77
325.7520	305.5000	20.2520	6.63
324.2639	300.8999	23.3640	7.76
310.9199	289.3000	21.6199	7.47
328.0598	307.3999	20.6599	6.72
355.4197	329.3999	26.0198	7.90
365.4399	317.1001	48.3398	15.24
356.8198	305.7000	51.1199	16.72
342.0798	299.1001	42.9797	14.37
345.2959	281.2000	64.0959	22.79
287.5198	255.5000	32.0198	12.53
259.0198	230.1000	28.9198	12.57

AVG. OF HOURLY PERCENT ERRORS= 7.94

PERCENT ERROR FOR TOTAL DAILY POWER= 92.89

BEST AVAILABLE COPY


Constrained Gain
Predicted and Actual
Wednesday 7 January 1976
HOUR
MW
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00



SPSS Gain Forecast and Actual Load

Wednesday 7 January 1976

PREDICTION FOR WED 7 JAN 76 ****

PREDICTION USES TUE 6 JAN 76 AS BASE DAY.

GAIN BASED ON MON 5 JAN 76

GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

PREDICTION	ACTUAL MW	DIFFERENCE	%
238.2199	293.3000	-55.0801	18.78
220.4999	233.2000	-12.7001	5.45
216.8200	229.2000	-12.3800	5.40
233.2801	223.8000	9.4801	4.24
225.4801	228.0000	-2.5199	1.11
234.8801	242.3000	-7.4199	3.06
269.5000	303.8000	-34.3000	11.29
340.2598	334.3000	5.9597	1.78
353.2998	337.2000	16.0999	4.77
339.3401	333.0000	6.3401	1.90
338.3599	337.3000	1.0598	.31
335.1001	322.8999	12.2002	3.78
314.7998	303.7000	11.0999	3.65
323.5999	304.6001	18.9998	6.24
312.8298	298.8000	14.0298	4.70
310.9797	281.3000	29.6797	10.55
334.8999	312.8999	22.0000	7.03
352.7998	333.0000	19.7998	5.95
337.7998	324.1001	13.6997	4.23
326.7998	300.8999	25.8999	8.61
312.8999	297.8999	15.0000	5.04
297.0000	278.8000	18.2000	6.53
276.7000	248.3000	28.3999	11.44
258.0999	226.2000	31.8999	14.10

AVG. OF HOURLY PERCENT ERRORS= 6.25

PERCENT ERROR FOR TOTAL DAILY POWER= 97.53

BEST AVAILABLE COPY

PREDICTION FOR WED 7 JAN 76 ****

PREDICTION USES TUE 6 JAN 76 AS BASE DAY.

GAIN BASED ON MON 5 JAN 76

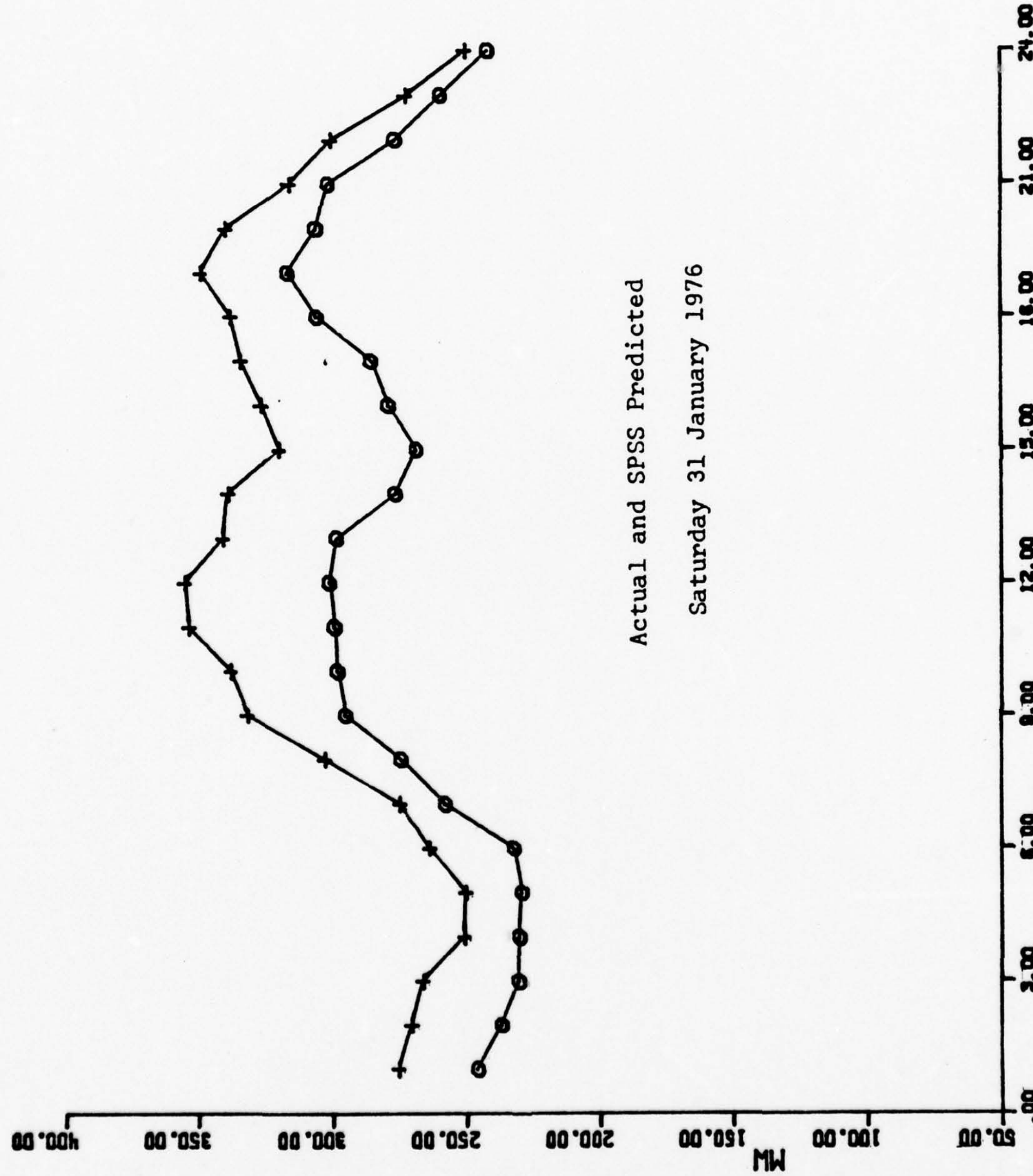
GAIN IS FIXED LESS THAN 1.5.

PREDICTION	ACTUAL MW	DIFFERENCE	%
253.3999	293.3000	-39.9001	13.60
235.8999	233.2000	2.6999	1.16
232.0000	229.2000	2.8000	1.22
236.8000	223.8000	13.0000	5.81
241.1001	228.0000	13.1001	5.75
251.6001	242.3000	9.3001	3.84
280.5000	303.8000	-23.3000	7.67
335.2000	334.3000	.8999	.27
343.3999	337.2000	6.2000	1.84
341.1001	333.0000	8.1001	2.43
335.5000	337.3000	-1.8000	.53
329.6001	322.8999	6.7002	2.08
313.5178	303.7000	9.8179	3.23
321.2141	304.6001	16.6140	5.45
309.0000	298.8000	10.2000	3.41
306.2712	281.3000	24.9712	8.88
337.7666	312.8999	24.8667	7.95
349.7856	333.0000	16.7856	5.04
337.0747	324.1001	12.9746	4.00
328.7664	300.8999	27.8665	9.26
315.0222	297.8999	17.1223	5.75
297.6499	278.8000	18.8499	6.76
288.1001	248.3000	39.8001	16.03
259.7122	226.2000	33.5122	14.82

AVG. OF HOURLY PERCENT ERRORS= 5.70

PERCENT ERROR FOR TOTAL DAILY POWER= 96.50

BEST AVAILABLE COPY



Actual and SPSS Predicted
Saturday 31 January 1976
HOUR
MW
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00

PREDICTIØN FØR SAT 31 JAN 76 ****

PREDICTIØN USES SAT 24 JAN 76 AS BASE DAY•

GAIN BASED ØN SUN 25 JAN 76

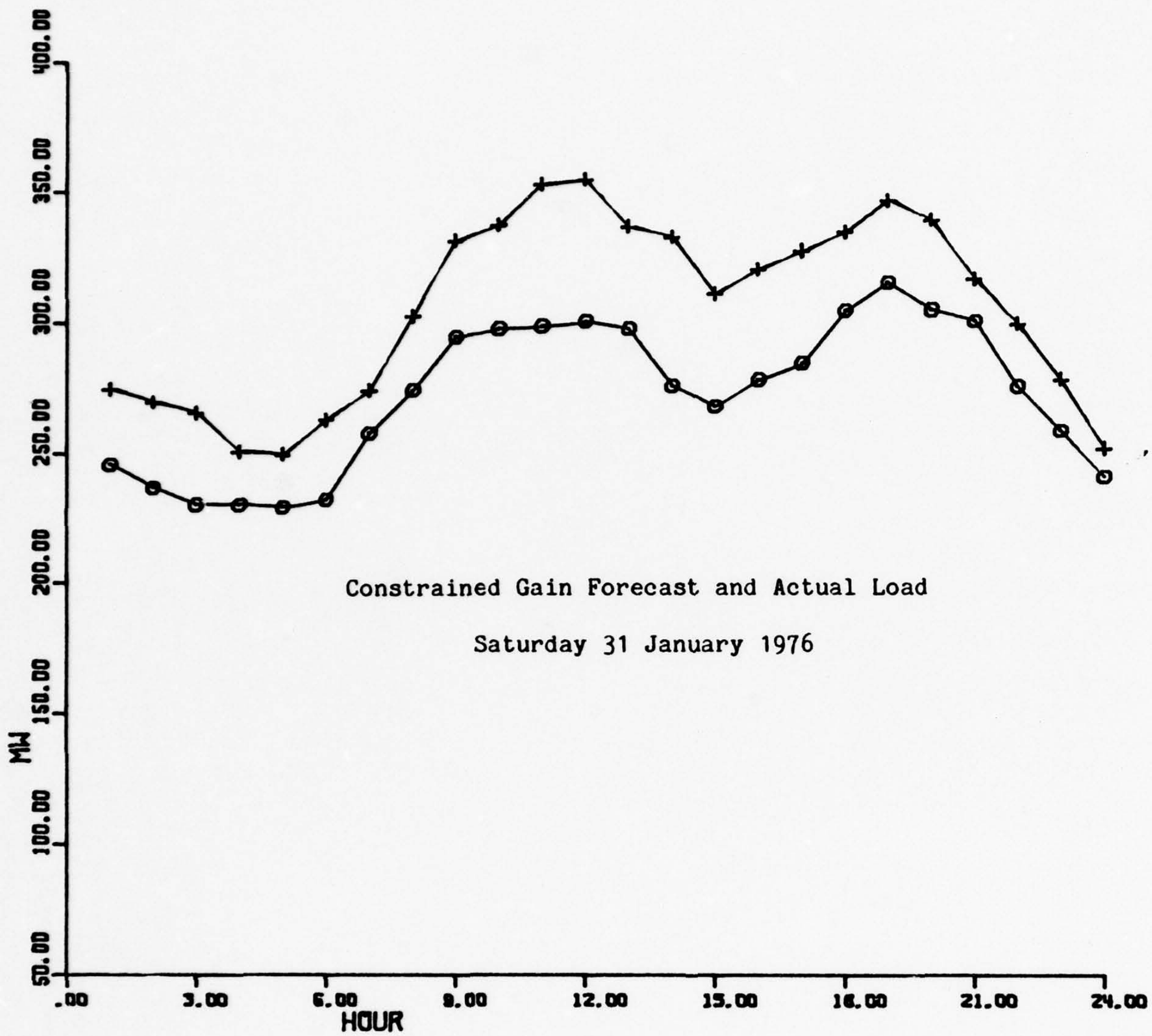
GAINS CØMPUTED BY SPSS FØR MØNTH ØF PREDICTIØN

PREDICTIØN	ACTUAL MW	DIFFERENCE	%
275•1899	245•4000	29•7899	12•14
270•3000	236•4000	33•9001	14•34
266•0898	230•0000	36•0898	15•69
250•6600	229•8000	20•8600	9•08
250•1100	228•9000	21•2100	9•27
263•5598	231•8000	31•7598	13•70
274•5000	257•6001	16•8999	6•56
302•2698	274•1001	28•1697	10•28
330•9497	294•5000	36•4497	12•38
337•2798	297•6001	39•6797	13•33
352•7698	298•5000	54•2698	18•18
354•2500	300•5000	53•7500	17•89
339•8799	297•7000	42•1799	14•17
337•8799	275•8000	62•0798	22•51
318•9641	267•8999	51•0642	19•06
325•6240	278•3000	47•3240	17•00
333•0400	284•8000	48•2400	16•94
336•6399	304•8000	31•8398	10•45
347•9797	315•5000	32•4797	10•29
338•3198	304•8999	33•4199	10•96
314•9797	300•6001	14•3796	4•78
299•6001	275•6001	24•0000	8•71
271•6797	258•7000	12•9797	5•02
249•3600	240•7000	8•6600	3•60

AVG• ØF HØURLY PERCENT ERRØRS= 12•35

PERCENT ERRØR FØR TØTAL DAILY PØWER= 58•95

BEST AVAILABLE COPY


Constrained Gain Forecast and Actual Load
Saturday 31 January 1976
MW
HOUR
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

PREDICTION FOR SAT 31 JAN 76 ****

PREDICTION USES SAT 24 JAN 76 AS BASE DAY.

GAIN BASED ON SUN 25 JAN 76

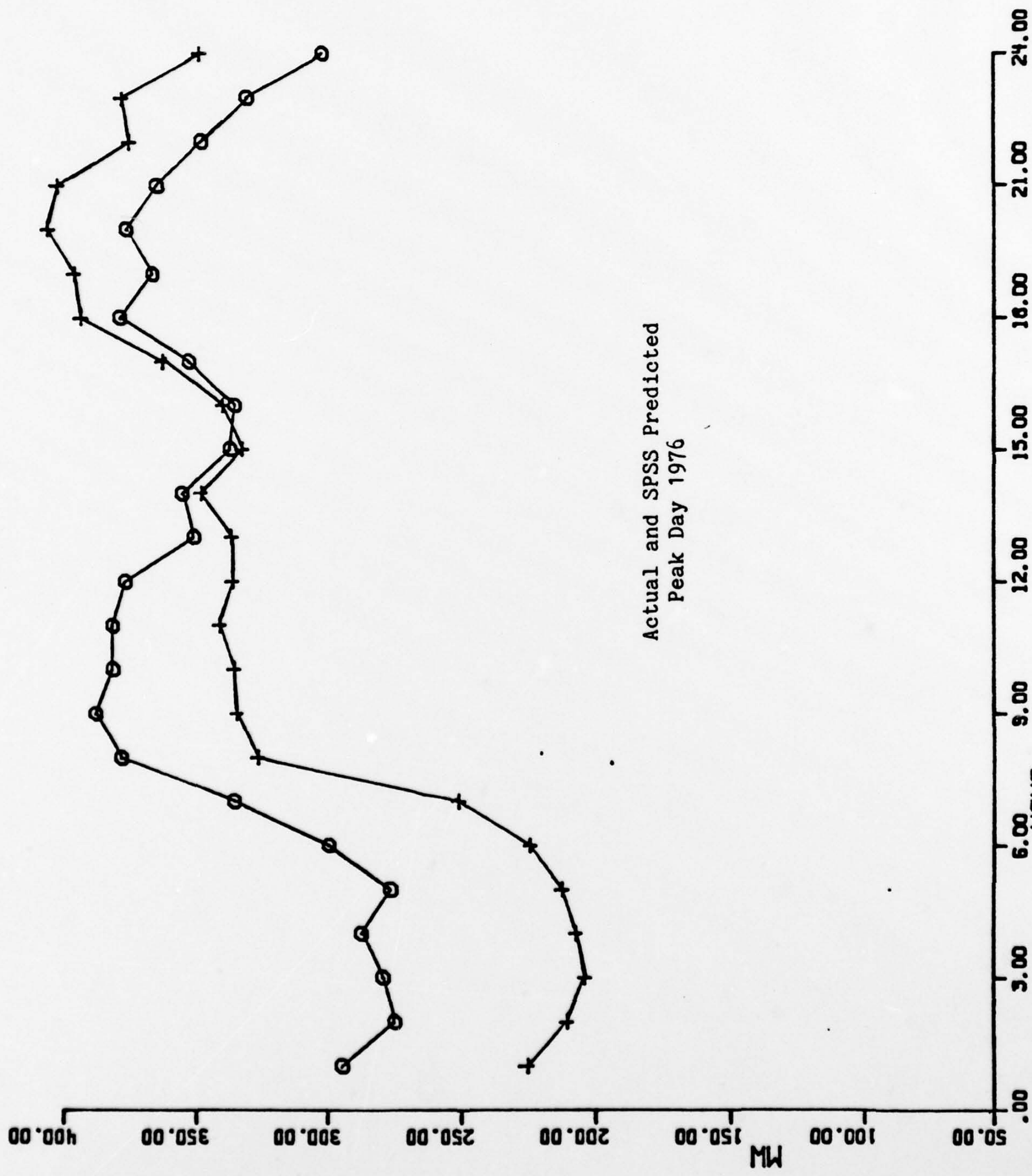
GAIN IS FIXED LESS THAN 1.5.

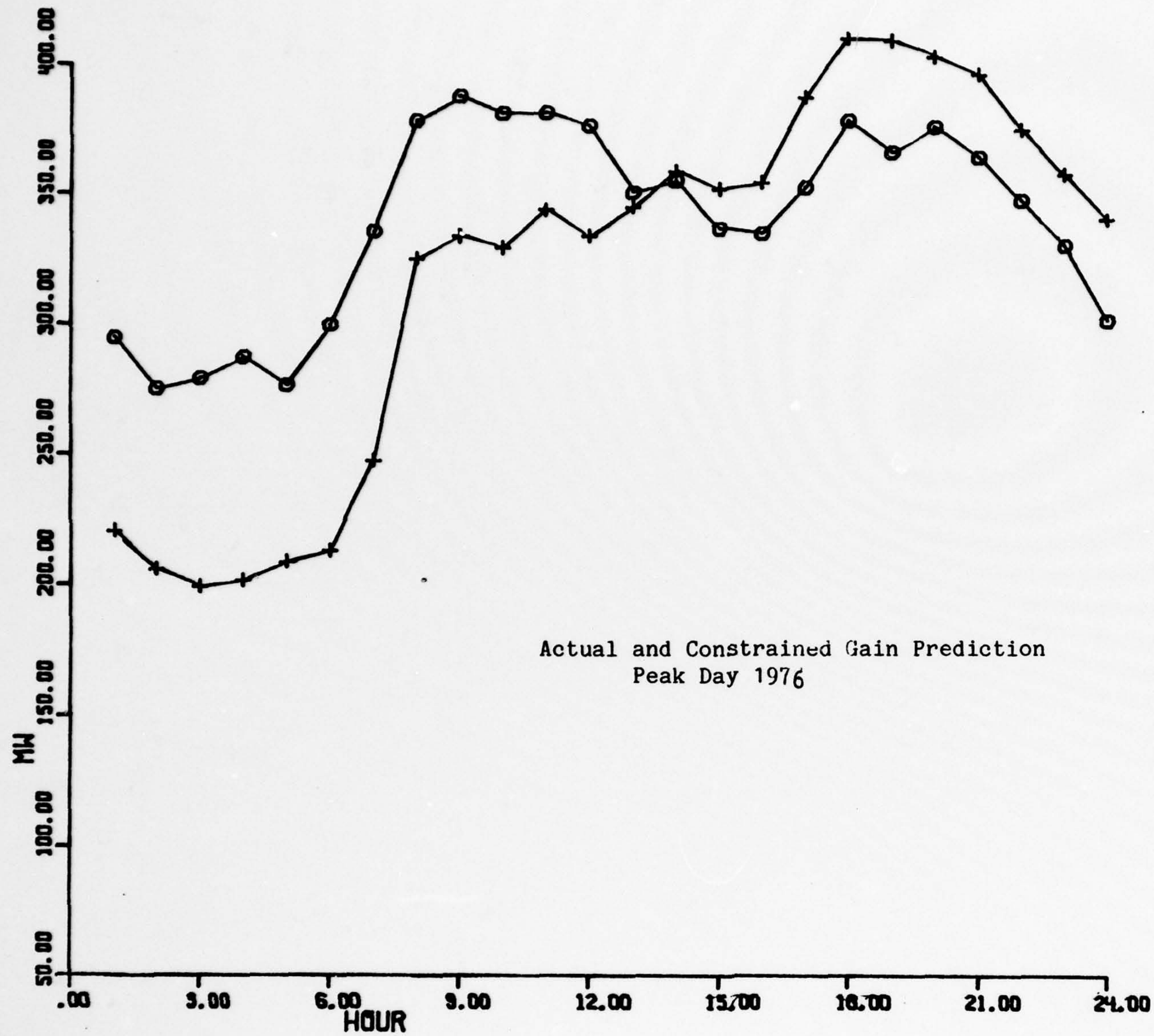
PREDICTION	ACTUAL MW	DIFFERENCE	%
274.5000	245.4000	29.1000	11.86
269.6001	236.4000	33.2001	14.04
265.3999	230.0000	35.3999	15.39
250.5000	229.8000	20.7000	9.01
249.4000	228.9000	20.5000	8.96
262.8000	231.8000	31.0000	13.37
274.0000	257.6001	16.3999	6.37
302.5000	274.1001	28.3999	10.36
331.3999	294.5000	36.8999	12.53
337.2000	297.6001	39.5999	13.31
352.8999	298.5000	54.3999	18.22
354.5000	300.5000	54.0000	17.97
336.6001	297.7000	38.9001	13.07
332.6001	275.8000	56.8000	20.59
311.1001	267.8999	43.2002	16.13
320.6001	278.3000	42.3000	15.20
327.6001	284.8000	42.8000	15.03
334.8000	304.8000	30.0000	9.84
346.7000	315.5000	31.2000	9.89
339.2000	304.8999	34.3000	11.25
316.8999	300.6001	16.2998	5.42
299.6001	275.6001	24.0000	8.71
278.3999	258.7000	19.7000	7.61
252.0000	240.7000	11.3000	4.69

AVG. OF HOURLY PERCENT ERRORS= 12.03

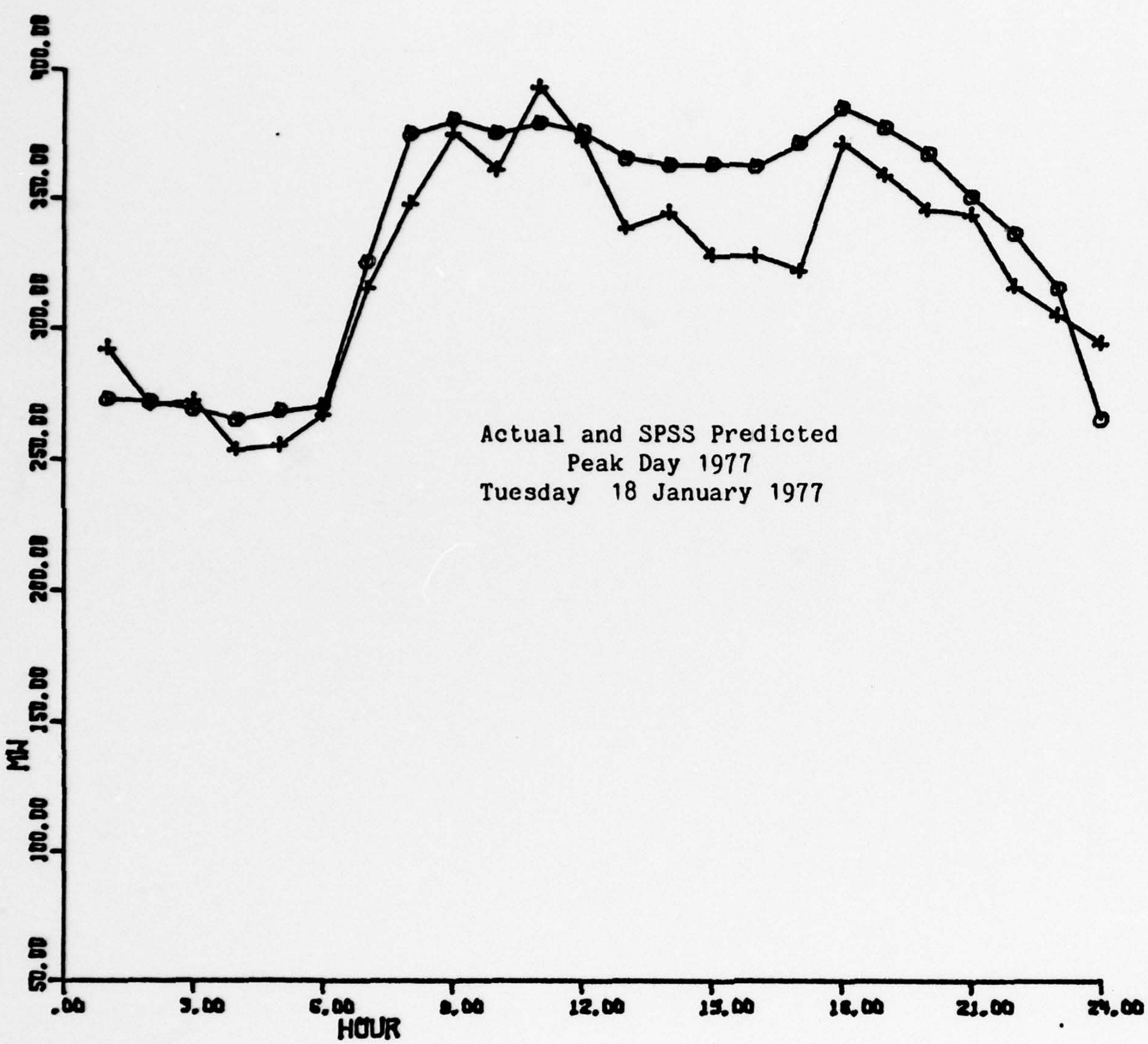
PERCENT ERROR FOR TOTAL DAILY POWER= 89.20

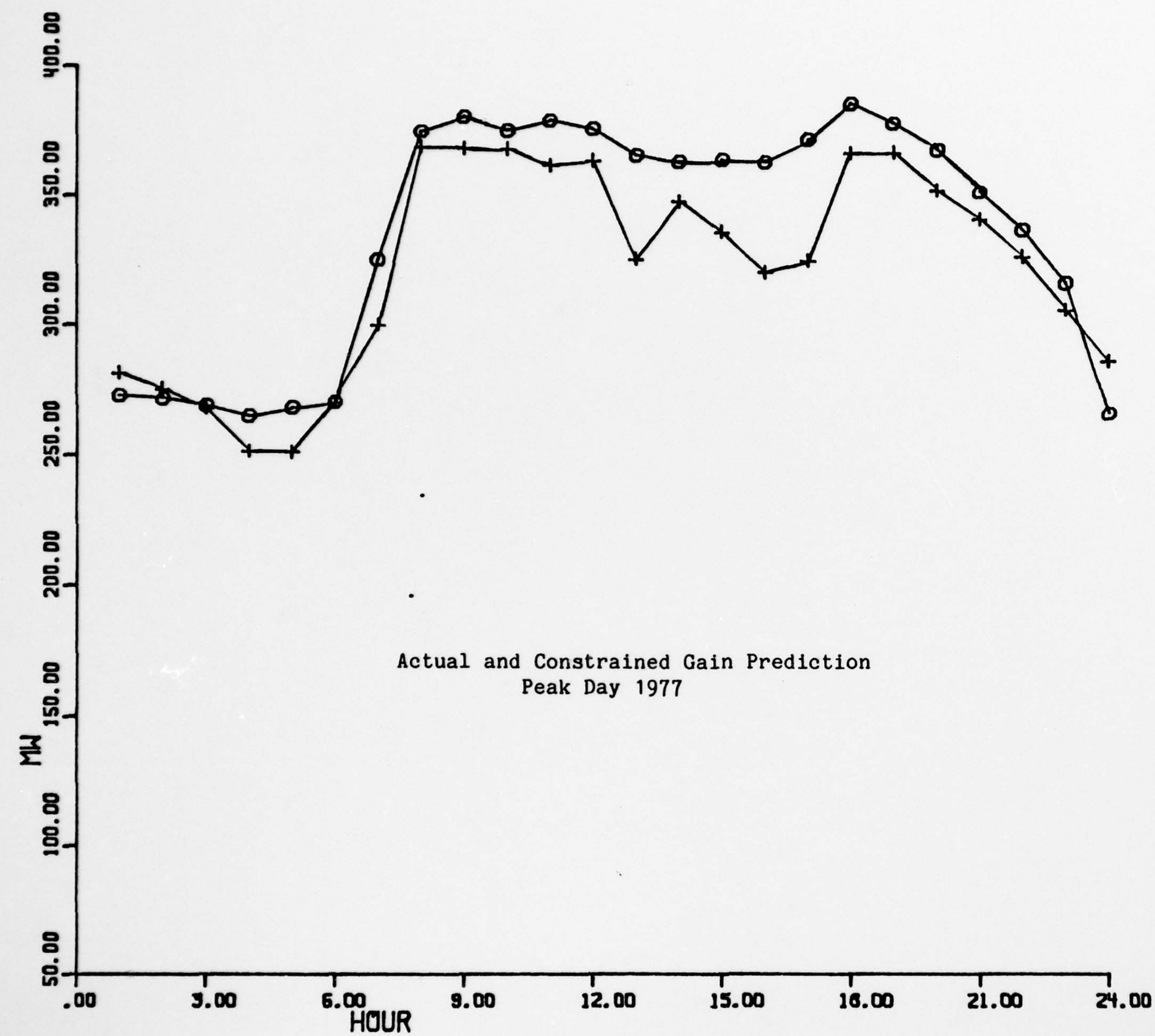
BEST AVAILABLE COPY


Actual and SPSS Predicted
Peak Day 1976
HOUR
MW
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00



Actual and Constrained Gain Prediction
Peak Day 1976


Actual and SPSS Predicted
Peak Day 1977
Tuesday 18 January 1977
MW
HOUR
50.00
100.00
150.00
200.00
250.00
300.00
350.00
400.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00


400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
MW
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00
HOUR
Actual and Constrained Gain Prediction
Peak Day 1977

BEST AVAILABLE COPY

PREDICTION FOR TUE 18 JAN 77 ****

PREDICTION USES FRI 14 JAN 77 AS BASE DAY.

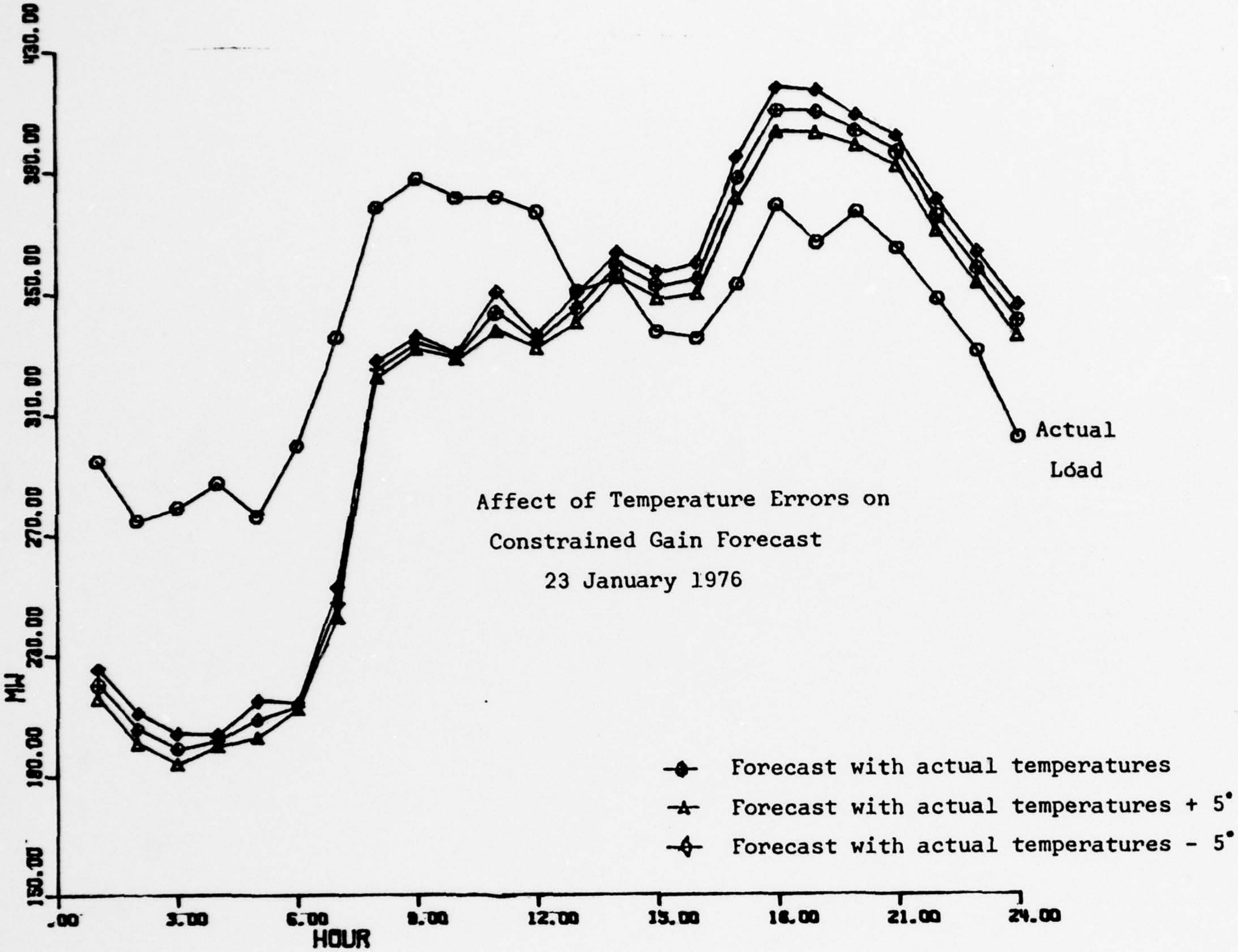
GAIN BASED ON THUR 13 JAN 77

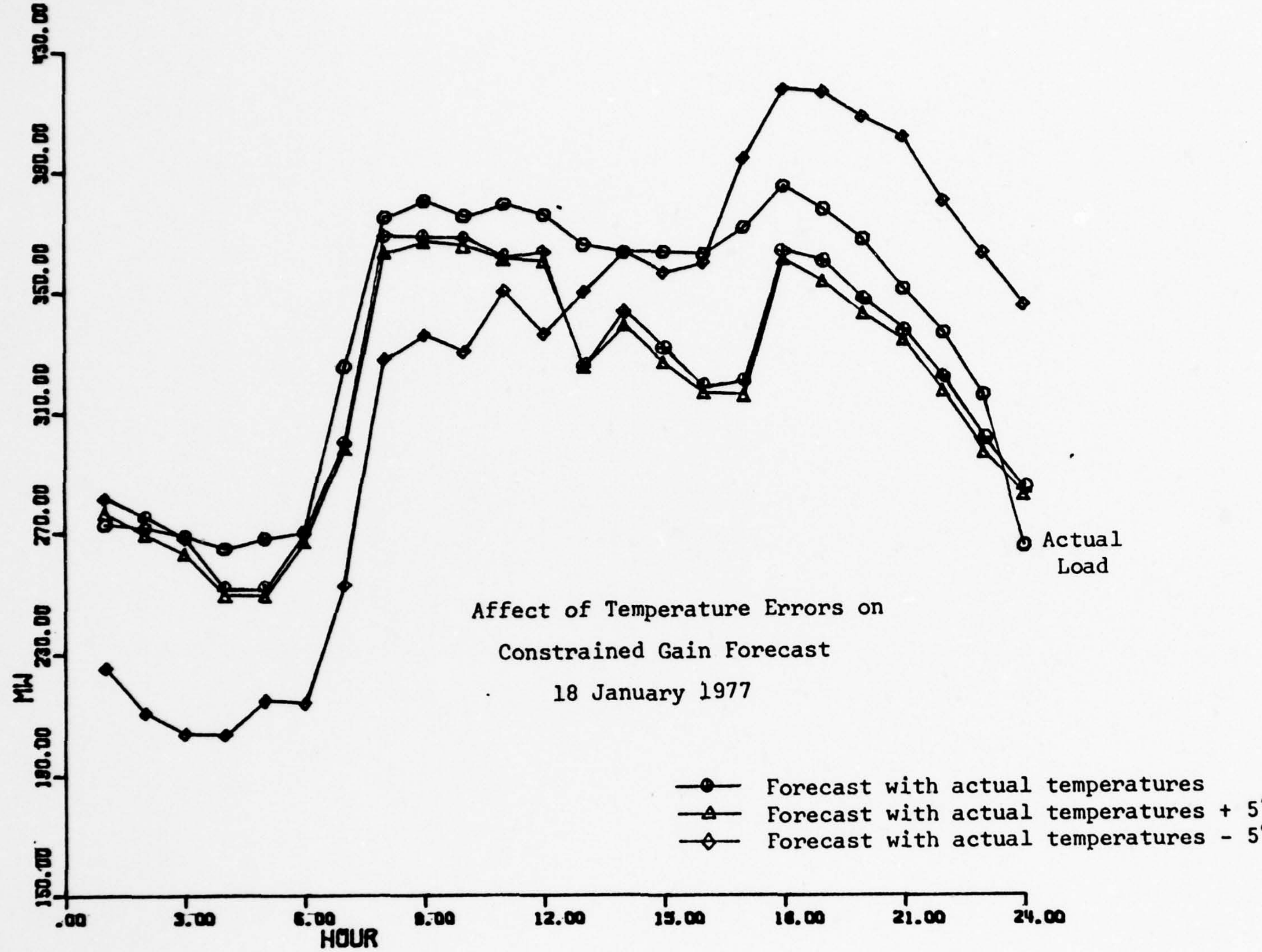
GAINS COMPUTED BY SPSS FOR MONTH OF PREDICTION

PREDICTION	ACTUAL MW	DIFFERENCE	%
292.2000	272.3999	19.8000	7.27
270.3579	271.2000	-.8420	.31
271.8799	268.5000	3.3799	1.26
253.3200	264.3999	-11.0799	4.19
254.9280	267.7000	-12.7720	4.77
266.6279	269.8000	-3.1721	1.18
315.2600	324.8000	-9.5400	2.94
347.8198	374.2000	-26.3801	7.05
374.6399	379.7000	-5.0601	1.33
360.4797	374.5000	-14.0203	3.74
392.3999	378.3999	14.0000	3.70
371.7598	374.8999	-3.1401	.84
338.2200	364.8000	-26.5801	7.29
344.2239	362.3999	-18.1760	5.02
327.6680	362.6001	-34.9321	9.63
327.5398	361.8000	-34.2603	9.47
321.8201	370.6001	-48.7800	13.16
370.5400	384.2000	-13.6599	3.56
358.4797	376.6001	-18.1204	4.81
345.2400	366.6001	-21.3601	5.83
343.3599	350.1001	-6.7402	1.93
315.8518	335.8000	-19.9482	5.94
304.9399	315.2000	-10.2600	3.26
294.1399	264.8999	29.2400	11.04

AVG. OF HOURLY PERCENT ERRORS= 4.98

PERCENT ERROR FOR TOTAL DAILY POWER= 103.51

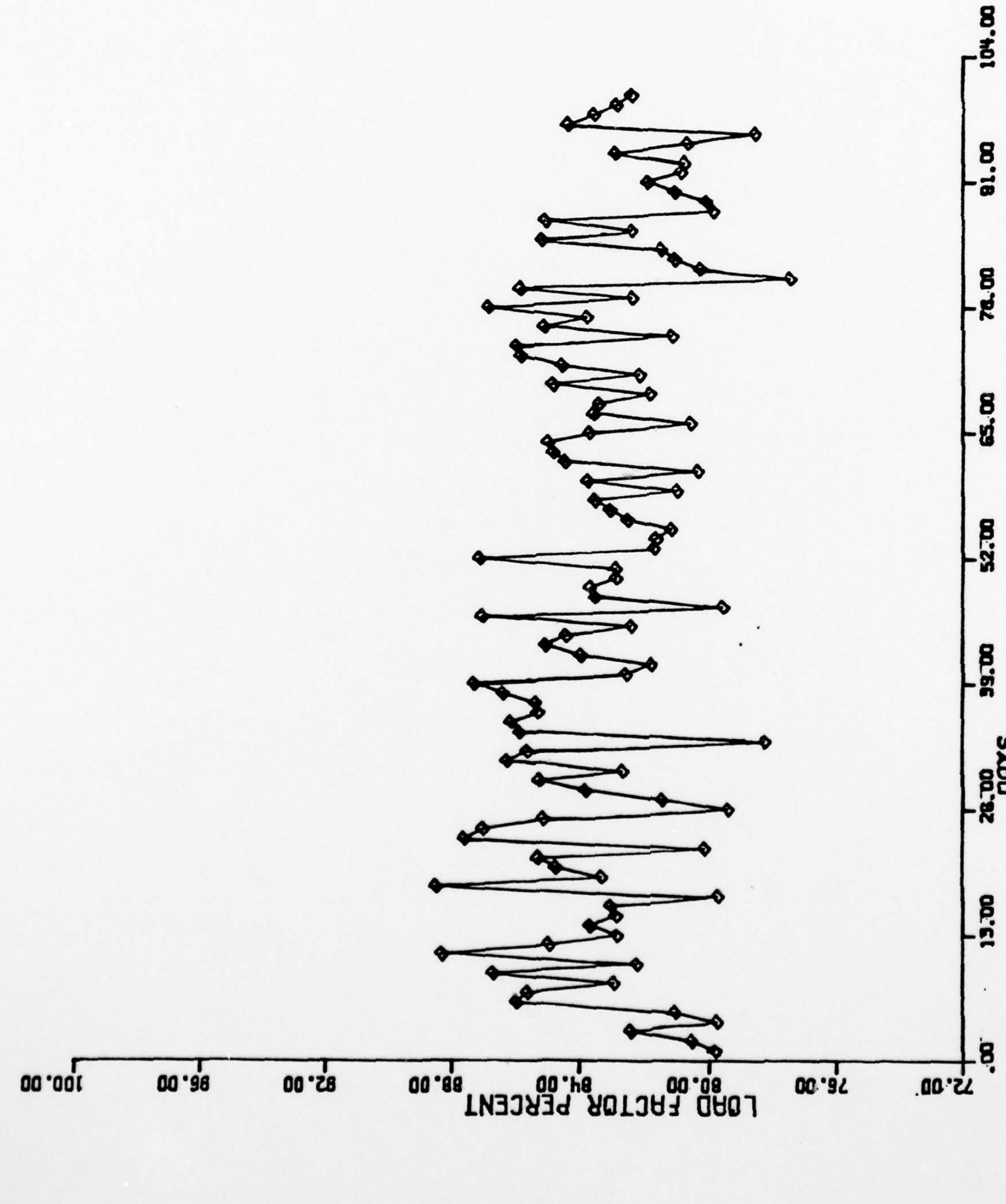

Affect of Temperature Errors on
Constrained Gain Forecast
23 January 1976
Actual
Load
Forecast with actual temperatures
Forecast with actual temperatures + 5°
Forecast with actual temperatures - 5°
MW
HOUR
150.00
180.00
210.00
270.00
310.00
350.00
380.00
430.00
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00


Affect of Temperature Errors on
Constrained Gain Forecast
18 January 1977
Actual
Load
Forecast with actual temperatures
Forecast with actual temperatures + 5°
Forecast with actual temperatures - 5°
MW
150.00
190.00
230.00
270.00
310.00
350.00
390.00
430.00
HOUR
.00
3.00
6.00
9.00
12.00
15.00
18.00
21.00
24.00

APPENDIX 5

LOAD FACTORS

Central Vermont Public Service Corporation daily load factors are presented for the first 100 days in both 1976 and 1977.

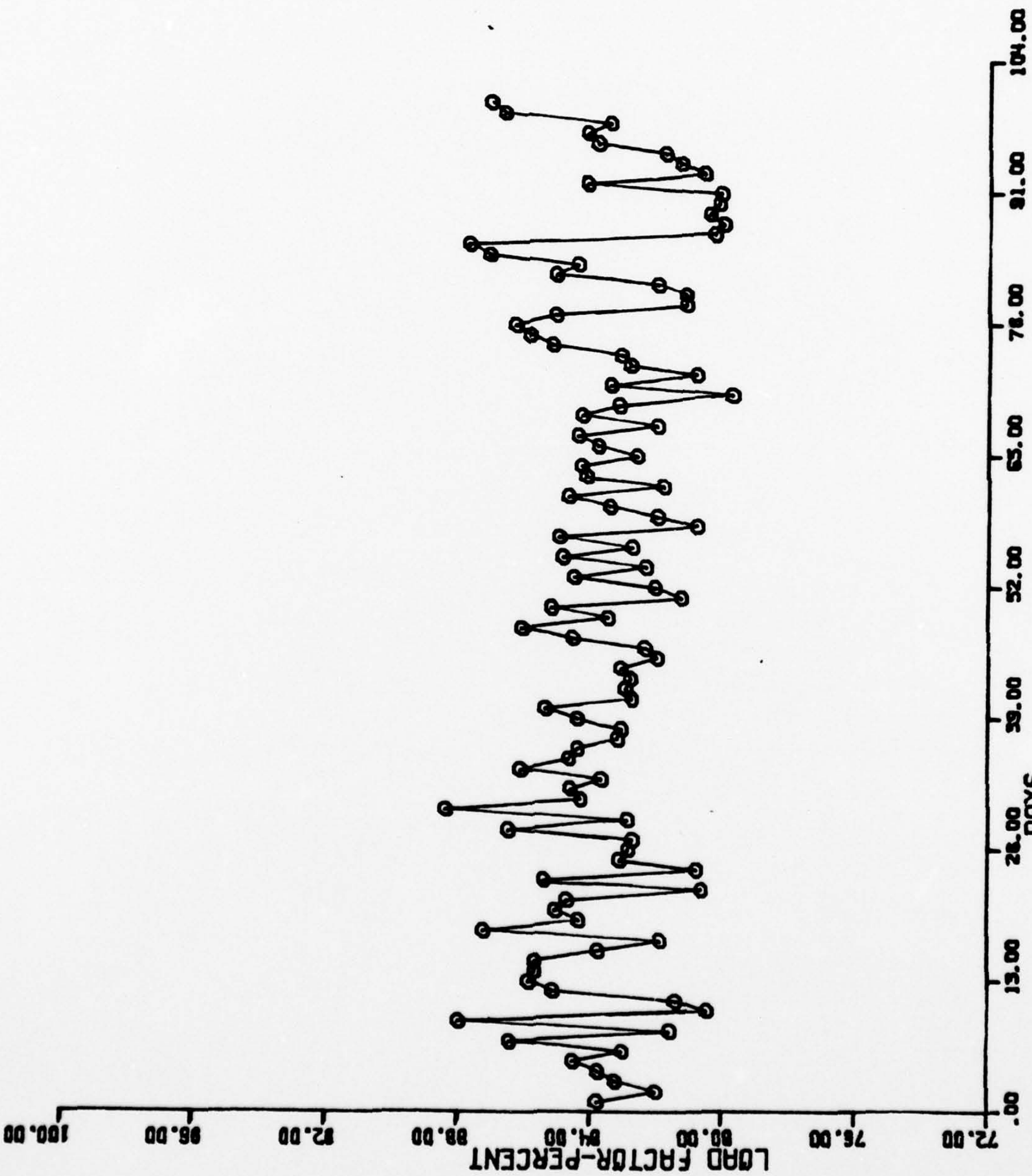


LOAD FACTORS FIRST 100 DAYS IN 1976

LOAD FACTORS FIRST 100 DAYS 1976

DAY	LOAD FACTOR	MIN.	MAX.	DAILY TOTAL
1	79.80	165.9	291.4	5580.59
2	80.54	204.5	347.4	6715.18
3	82.43	188.3	305.3	6040.09
4	79.76	167.5	290.0	5551.29
5	81.06	212.5	375.5	7305.38
6	85.94	254.0	365.4	7536.98
7	85.59	223.8	337.3	6928.78
8	82.94	189.8	345.4	6875.09
9	86.67	245.3	363.0	7551.09
10	82.24	234.7	353.9	6985.19
11	88.29	248.4	322.9	6841.78
12	84.93	210.3	350.2	7138.09
13	82.85	216.5	342.2	6803.99
14	83.67	174.9	321.3	6451.78
15	82.87	202.6	345.0	6861.68
16	83.04	226.7	363.9	7252.28
17	79.71	204.1	349.5	6686.09
18	88.45	236.8	317.7	6744.09
19	83.31	248.1	388.7	7771.48
20	84.72	231.3	355.9	7236.58
21	85.27	196.7	325.6	6663.08
22	80.15	191.8	378.0	7271.39
23	87.58	274.6	386.9	8132.38
24	86.98	248.4	354.7	7404.78
25	85.11	216.8	294.9	6023.49
26	79.42	190.7	342.7	6532.18
27	81.47	170.0	316.6	6190.29
28	83.82	180.0	323.1	6499.58
29	85.21	206.5	324.1	6627.69
30	82.67	202.0	342.4	6793.19
31	86.24	228.9	315.5	6530.38
32	85.60	186.9	266.3	5470.89
33	78.27	164.1	361.5	6790.69
34	85.86	220.8	338.5	6975.09
35	86.12	218.7	335.1	6925.88
36	85.27	228.5	338.2	6921.39
37	85.35	209.7	333.7	6835.68
38	86.38	223.2	308.9	6403.88
39	87.29	195.4	262.3	5494.99
40	82.57	181.2	317.9	6299.99
41	81.78	201.9	321.7	6313.89
42	83.94	165.5	291.2	5866.08
43	85.02	185.3	300.9	6139.49
44	84.39	172.3	289.6	5865.68
45	82.41	190.2	305.3	6038.38
46	87.02	180.1	273.9	5720.59
47	79.55	155.2	298.4	5697.19
48	83.51	168.6	308.4	6180.79
49	83.66	181.4	317.1	6366.79
50	82.87	176.6	309.8	6161.58

51	82.88	185.2	313.6	6237.69
52	87.09	194.3	274.7	5741.69
53	81.68	149.0	249.0	4881.29
54	81.62	187.8	342.4	6706.89
55	81.16	220.7	337.0	6564.38
56	82.51	183.8	295.5	5851.59
57	83.06	168.9	289.4	5769.29
58	83.52	165.9	281.0	5632.49
59	80.99	160.5	283.5	5510.39
60	83.73	174.3	250.1	5025.69
61	80.34	148.5	301.6	5815.09
62	84.44	180.2	319.1	6467.08
63	84.80	194.0	325.4	6622.19
64	84.93	195.3	306.7	6251.48
65	83.67	169.0	281.4	5650.99
66	80.56	160.5	275.8	5332.39
67	83.55	174.4	255.6	5125.39
68	83.38	182.5	321.8	6439.68
69	81.83	216.9	338.4	6645.89
70	84.80	201.4	306.1	6229.79
71	82.14	178.1	311.4	6138.89
72	84.53	204.2	312.9	6348.18
73	85.81	173.9	261.3	5381.09
74	85.95	164.2	226.0	4661.99
75	81.15	153.1	292.9	5704.79
76	85.07	190.4	319.7	6527.18
77	83.76	197.4	324.6	6525.59
78	86.82	212.6	313.4	6530.39
79	82.37	193.6	311.9	6165.68
80	85.83	158.9	227.1	4677.89
81	77.45	119.3	219.6	4082.10
82	80.25	142.0	310.4	5977.99
83	81.05	202.0	305.4	5940.99
84	81.48	165.9	274.8	5373.80
85	85.15	147.7	259.9	5311.09
86	82.41	157.6	261.5	5171.89
87	85.04	147.8	216.8	4424.70
88	79.85	123.7	220.4	4223.89
89	80.07	151.7	280.0	5380.79
90	81.05	163.0	269.0	5232.49
91	81.89	144.1	261.7	5143.29
92	80.87	146.6	283.3	5498.79
93	80.75	166.0	279.9	5424.19
94	82.89	148.6	237.5	4724.69
95	80.66	142.3	217.2	4204.70
96	78.56	149.5	285.1	5375.29
97	84.36	153.4	261.1	5286.39
98	83.56	159.2	266.9	5352.48
99	82.86	165.8	278.9	5546.59
100	82.38	159.0	277.1	5478.69



Load Factors First 100 Days in 1977

LOAD FACTORS FIRST 100 DAYS 1977

DAY	LOAD FACTOR	MIN.	MAX.	DAILY TOTAL
1	83.74	217.7	317.2	6375.18
2	81.96	195.8	288.6	5676.98
3	83.18	192.1	340.0	6787.18
4	83.72	200.1	340.9	6849.49
5	84.47	218.2	346.8	7030.68
6	82.97	227.1	362.6	7219.98
7	86.37	202.2	327.2	6782.79
8	81.54	198.7	323.8	6336.99
9	87.92	223.6	291.1	6142.59
10	80.41	209.3	361.1	6969.09
11	81.38	206.6	369.2	7211.19
12	85.10	235.5	365.6	7467.18
13	85.81	242.0	368.5	7588.69
14	85.63	241.0	361.0	7418.99
15	85.63	219.9	314.4	6461.59
16	83.72	197.4	294.7	5921.59
17	81.84	212.7	385.6	7573.38
18	87.15	264.4	384.2	8036.07
19	84.31	247.1	363.5	7355.58
20	85.00	216.3	333.7	6807.18
21	84.66	208.6	334.0	6786.18
22	80.59	211.6	344.5	6663.59
23	85.35	212.8	293.0	6001.79
24	80.75	196.2	344.2	6670.89
25	83.08	189.6	322.0	6420.19
26	82.81	182.7	331.4	6586.48
27	82.69	213.1	351.5	6975.69
28	86.43	237.8	358.3	7432.08
29	82.85	220.4	346.2	6883.79
30	88.32	232.4	303.7	6437.48
31	84.26	221.1	365.3	7387.68
32	84.56	227.1	359.7	7299.49
33	83.63	238.8	364.5	7316.39
34	86.05	239.4	349.6	7219.88
35	84.61	208.8	326.8	6635.89
36	84.34	204.9	303.5	6143.59
37	83.14	186.9	292.3	5832.19
38	83.02	212.6	356.9	7110.79
39	84.36	230.0	345.7	6998.98
40	85.34	215.1	331.0	6779.08
41	82.72	189.4	313.0	6213.59
42	82.90	198.3	315.2	6270.88
43	82.76	169.3	268.8	5339.19
44	83.05	146.6	241.6	4815.59
45	81.96	150.1	300.5	5911.19
46	82.32	178.4	319.2	6305.99
47	84.49	208.4	337.9	6852.09
48	86.02	237.8	351.4	7254.18
49	83.43	228.6	344.8	6903.68
50	85.14	202.5	298.5	6099.19

51	81.20	176.6	282.2	5499.79
52	82.00	178.6	323.1	6358.38
53	84.46	217.5	343.3	6958.79
54	82.28	198.4	337.9	6672.78
55	84.81	203.6	332.4	6765.68
56	82.70	186.7	312.5	6202.79
57	84.92	174.4	266.5	5431.50
58	80.74	159.8	249.6	4836.89
59	81.95	154.4	301.7	5934.19
60	83.39	179.1	305.7	6118.29
61	84.64	193.9	311.5	6327.88
62	81.76	189.7	307.6	6036.08
63	84.08	184.6	312.8	6311.99
64	84.22	167.1	260.5	5265.59
65	82.54	151.9	245.3	4859.19
66	83.73	157.7	295.4	5935.79
67	84.34	177.4	287.8	5825.49
68	81.93	175.3	284.1	5586.09
69	84.22	146.4	255.9	5172.59
70	83.10	153.8	262.2	5229.09
71	79.68	134.4	238.4	4558.69
72	83.36	125.9	215.5	4311.20
73	80.77	126.8	277.4	5377.59
74	82.77	155.3	276.0	5482.79
75	83.05	157.0	286.2	5704.69
76	85.14	174.7	294.3	6013.79
77	85.82	191.1	305.8	6298.69
78	86.24	182.0	261.8	5418.49
79	85.02	173.7	236.4	4823.89
80	81.06	157.3	293.8	5715.88
81	81.08	173.5	313.6	6102.29
82	81.93	159.4	295.9	5818.59
83	85.03	177.4	297.2	6065.29
84	84.36	182.4	309.3	6262.19
85	87.01	183.5	256.9	5364.39
86	87.64	157.3	213.7	4494.89
87	80.22	142.0	278.4	5359.89
88	79.97	146.8	272.4	5227.98
89	80.38	135.3	264.8	5108.29
90	80.10	135.8	270.9	5207.99
91	80.04	160.8	279.4	5367.39
92	84.11	158.5	244.5	4935.49
93	80.54	129.5	216.2	4179.00
94	81.25	154.5	285.4	5564.98
95	81.71	160.5	293.6	5757.69
96	83.76	169.5	284.5	5718.89
97	84.07	175.7	291.1	5873.49
98	83.38	168.9	282.2	5647.39
99	86.58	180.1	254.9	5296.38
100	86.99	157.3	211.4	4413.70